CANADIAN ENERGY

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CANADIAN ENERGY

Supply and Demand 1993 - 2010

TRENDS AND ISSUES

NATIONAL ENERGY BOARD

Conversion Factors – Metric to Imperial Units[1]

metre (m)	=	3.28 feet
cubic metre (m³) of oil	=	6.3 barrels
cubic metre (m³) of natural gas	=	35.3 cubic feet
litre (L)	=	0.22 Imperial gallon
gigajoule (GJ)	=	950.0 cubic feet of natural gas at 1 000 Btu per cubic foot, or 0.165 barrels of oil, or 0.28 megawatt hours of electricity
tonne (t)	=	2 200 pounds

Abbreviations

gigajoule (GJ)	=	10^9 Joules (J)
terajoule (TJ)	=	10^{12} J
petajoule (PJ)	=	10^{15} J
exajoule (EJ)	=	10^{18} J
kilowatt (kW)	=	10^3 watts
megawatt (MW)	=	10^3 kilowatts
megawatt hour (MW.h)	=	10^3 kilowatt hours (kW.h)
gigawatt hour (GW.h)	=	10^6 kW.h
terawatt hour (TW.h)	=	10^9 kW.h

1 Approximate conversion factors

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Abbreviations of Names and Terms

Act	the *National Energy Board Act*
Alt Macro	Alternative Macroeconomic assumption
AMP	(Alberta) Average Market Price
(the) Board or NEB	(the) National Energy Board
CEC	California Energy Commission
CGA	Canadian Gas Association
Current Tech (or CT)	Current Technology case
DRI	Data Resources Incorporated
DSM	Demand Side Management
EIA	Export Impact Assessment
ERCB	Alberta Energy Resources Conservation Board
FERC	Federal Energy Regulatory Commission (U.S.)
GDP	Gross Domestic Product
HFO	Heavy fuel oil
High Tech (or HT)	High Technology case
IEA	International Energy Agency
Informetrica	Informetrica Limited
IRP	Integrated Resource Planning
LFO	Light fuel oil
LNG	Liquefied Natural Gas
MBP	Market-Based Procedure
NAFTA	North American Free Trade Agreement
NGL	Natural Gas Liquids
NGMA	Natural Gas Market Assessment

Abbreviations of Names and Terms (continued)

NPC	National Petroleum Council (U.S.)
NRCan	Natural Resources Canada
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PEL	Petroleum Economics Limited
PNW	Pacific Northwest (U.S.)
RDP	Real Domestic Product
U.S.	United States
VOC	Volatile Organic Compounds
WCSB	Western Canada Sedimentary Basin
WEFA	Wharton Econometric Forecasting Associates
WTI	West Texas Intermediate crude oil
1986 Report	National Energy Board, *Canadian Energy Supply and Demand 1985-2005*, Summary and detailed reports, October, 1986
1988 Report	National Energy Board, *Canadian Energy Supply and Demand 1987-2005*, Summary and detailed reports, September, 1988
1991 Report	National Energy Board, *Canadian Energy Supply and Demand, 1990-2010*, Summary and detailed reports, June 1991

Foreword

The National Energy Board ("NEB" or "the Board") was created by an Act of Parliament in 1959. The Board's regulatory powers under the *National Energy Board Act* ("the Act") include the authorizing of the export of oil, gas and electricity, of the construction of interprovincial and international oil and gas pipelines and international power lines, the setting of just and reasonable tolls for pipelines under federal jurisdiction and the regulation of oil and gas activities on Canada lands in the north. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception, the Board has prepared and maintained projections of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. In a July 1987 decision in which the Board adopted the Market-Based Procedure ("MBP") for regulating natural gas exports, the Board indicated its intention to continue to produce and publish these *Canadian Energy Supply and Demand* reports as one component of the ongoing monitoring part of the MBP. The latest of these reports was issued in the fall of 1991.

The objectives of this report are:

- to provide a comprehensive "all energy" market analysis and outlook to serve as a standard of reference for all parties interested in Canadian energy issues;

- to provide a framework for public discussion on emerging energy issues of national importance; and

- to monitor the prospects for the supply, demand and price of natural gas in Canada pursuant to the MBP.

In conducting its analysis the Board, or Board staff, has always obtained the views of interested parties. Over the years a number of changes have been made to the process of obtaining external views. In the reports of the late 1970s and early 1980s external views were gathered by submissions requested by the Board which were sometimes the subject of examination in public hearings. Starting with the 1984 report, submissions were no longer subject to public examination; in subsequent reports, information was gathered from interested parties on a more informal basis.

In this version of *Canadian Energy Supply and Demand*, Board staff continued to use an informal consultation process involving two rounds of discussions. The initial round was conducted at an early, formative, stage of the analysis. It involved dialogue about issues, the appropriate analytical approach and report format. A brief report on these consultations, and on the actions that resulted from them, was made available to interested parties in July 1993. A second round of consultations, to discuss preliminary results, was held in December 1993. Important differences between the views expressed by consultees and the Board's analysis are noted and discussed in the report. In addition Board staff engaged in extensive consultations with many sectors of the energy community. We greatly appreciate the advice we received and the interchange of views during our consultations and we thank those who contributed their time and expertise.

These reports are issued by the Board for the information of the public. A number of parties have raised concerns over the use of *Canadian Energy Supply and Demand* reports in the Board's regulatory proceedings, and questioned whether these reports are an official reflection of Board views. The Board therefore wishes to clarify its views in this regard.

The Board recognizes that parties have not had the opportunity to examine or test the findings and conclusions contained in these reports in a public forum. Material from them may be used as part of the evidentiary record in particular regulatory proceedings to the extent that any party chooses to rely on such material, just as it could rely on any public document. In such a case, the material in effect is adopted by the party introducing it. In this respect, there has been no change in the way in which the report is used by the Board.

This report contains a discussion of the main supply and demand trends and issues. A technical report and statistical appendix contain more analytical detail and supporting information.

Chapter 1

INTRODUCTION

Since its inception the National Energy Board has published assessments of the long-term outlook for energy in Canada. In the period since 1981 four reports have been issued. The Board has always recognized that there is considerable uncertainty about the future evolution of energy markets stemming from both demand and supply behaviour. Over a period as long as twenty years fundamental changes can be expected to affect society, the economy, and government policies, all of which can profoundly influence the evolution of energy markets. For purposes of long-term analysis a single estimate of the most likely course of energy supply and demand is not particularly useful or suitable. In fact, the Board has explicitly stated in recent reports that its analysis is not intended to provide a "forecast" but, rather, to give a broad assessment of the implications of possible variations in key underlying variables, such as world oil prices, for the long-run energy outlook. This report continues that tradition.

Further, the analysis in this report pertains to long-run trends in energy markets; it does not purport or attempt to assess year-to-year fluctuations in the demand for and supply of energy or in energy prices. Fluctuations will occur on a monthly, annual and multi-year basis, as recent experience demonstrates, but they are not necessarily indicative of longer run trends. We do not attempt to analyze the prospects for the emergence of surpluses of commodities such as natural gas or of shortages as reflected in short-term price spikes. In reasonably well functioning markets sustained surpluses or "shortages" will not occur. There can, of course, be difficulties associated with supply/demand imbalances and sharp changes in price but these are short run and transitory in nature; they are not a continuing characteristic of markets over long periods of time.[1]

The response of markets, in Canada and elsewhere, to the oil price shocks of the 1970s and, more recently, to changing circumstances in North American natural gas markets, is strong evidence of the validity of this view. Over long periods of time such as the period considered in this report, the trends in energy supply, demand and prices will reflect the influence of changes in the fundamentals of technology, consumer and producer behaviour and government policies.

It is also important to note that our analysis is restricted in that we do not speculate on the future course of government policies, including energy and environmental policies. Rather we conduct an analysis of plausible trends in energy market variables within the currently existing policy framework. For example, although this report analyzes the implications of energy supply and demand trends for levels of greenhouse gas emissions, we do not develop and analyze possible government policies to achieve greenhouse gas emissions targets. There is also much public discussion of the prospects for policy initiatives related to increased use of alternative and renewable forms of energy. In fact, it is frequently stated that such new energy forms can only be viable with changes to government policies. We assess the prospects for such energy forms based on their current and prospective costs and the prices of competing fuels. While we conclude that they are not generally commercially viable with present policies, we do not assume policy changes and therefore we do not project increased use.

We have, in recent years, canvassed readers of these reports as to their usefulness and as to the appropriate structure and framework of analysis. Two opinions have been strongly expressed:

- the reports should emphasize the key uncertainties related to the future course of energy supply and demand and the implications of such uncertainties; and

- notwithstanding the importance of analyzing these implications, it is important to have an integrated and consistent quantitative analysis, which includes all energy commodities, supporting observations and conclusions and the Board should have a view about the most likely evolution of energy markets.

These views have led us to change the format and the manner of presenting the results of the analysis. In

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1   This does not mean that these transitory phenomena are unimportant; rather, it is to say that they are best addressed by other kinds of analysis. Two recent examples of short-run analysis of natural gas markets are: National Energy Board, *Natural Gas Market Assessment, Canadian Natural Gas Market Mechanisms: Recent Experiences and Developments*, November 1993 and National Energy Board, *Natural Gas Market Assessment, Natural Gas Supply Western Canada, Recent Developments (1982-1992), Short-Term Deliverability Outlook (1993-1996)*, November 1993.

order to respond to a diverse readership two reports will be published. The present report focuses on the broad outlines of prospective energy market developments under different underlying assumptions about the values of key variables. The results are presented as a range of possible outcomes. A separate technical report provides detailed descriptions of the analytical methods used and the quantitative results. The quantitative analysis will be of value to users who wish to develop their own views of prospects or to have a detailed assessment of the impact of alternative assumptions. Neither report purports to contain a "forecast" of energy market developments.

Framework of Analysis

In each of its energy outlook reports issued in recent years, the Board has analyzed the implications for the Canadian energy market of different assumptions about the future course of key variables. In reports issued before 1991, the emphasis was on the implications of alternative profiles of world oil prices and economic growth. In 1991 the analysis was expanded, in view of interest in the prospects for natural gas markets, to incorporate a broader assessment of the implications of alternative estimates of potential natural gas resources. It also provided, for the first time, estimates of levels of greenhouse gas emissions arising from the supply and demand projections. In determining the analysis to be conducted for this report we decided:

- not to repeat earlier analysis where, in our view, it remains valid; and

- to concentrate our efforts on areas of greatest interest which are also relevant to the work of the Board.

Accordingly, this report focuses on assessing the implications of alternative assumptions about technological progress as they affect the costs of supplying natural gas in the future. It also continues to provide assessments of the implications of new and ongoing uncertainties which are particularly important for energy demand and for the supply of specific energy forms.

For natural gas, the recent emergence of a close balance between demand and supply in an increasingly integrated North American gas market, following a prolonged period of excess productive capacity, has led to renewed interest and concern about the prospects for natural gas prices. There is also emerging interest in the impact of technological progress on the cost of finding and producing incremental natural gas reserves.

The issues of the price and supply cost of natural gas were frequently raised and discussed during consultations we conducted in the course of preparing this report. They were also main topics of interest during the review conducted by the Board in 1993 of the Export Impact Assessment[2] component of the procedure used by the Board in the regulation of long-term natural gas exports. These matters were also the focus of a comprehensive study by the U.S. National Petroleum Council on the outlook for North American supply and demand of natural gas[3].

A major part of the analytical effort therefore focused on the development of two cases differentiated by alternative views about the impact of technological change on the costs of finding, developing and producing natural gas. Other assumptions, such as those regarding the future course of oil prices, economic growth, and energy transportation costs, are common to the two cases. The potential impacts of different oil prices, economic growth and other factors are examined in sector-specific analysis. A summary of the framework of analysis appears in Table 1-1.

The Current Gas Supply Technology ("Current Tech") case assumes that existing technologies related to the finding and production of natural gas will evolve during our study period, resulting in some moderation in the rate of increase in gas supply costs through time but that no new technologies are developed. Natural gas supply costs rise with increasing production as new fields are explored and developed. This assumption is similar to the approach used in past Board reports, and is the traditional approach to natural gas supply analysis.

The High Gas Supply Technology ("High Tech") case, on the other hand, assumes that continued technological advances will, to a large extent, offset increases in the costs of gas supply even as new reserves are found and produced. This concept is consistent with the general observation that most mineral commodities have exhibited flat or declining supply costs throughout the extensive historical periods of their exploitation. This approach generates a considerably flatter profile for future supply costs compared to the Current Tech case. In other words, industry supply costs are substantially lower in the High Tech case, which, other things equal, imply lower market prices for gas than in the Current Tech case.

2   National Energy Board, *Export Impact Assessment Workshop, A Summary of Discussion*, 1 April 1993.

3   National Petroleum Council, *The Potential for Natural Gas in the United States*, December 1992.

The differences in natural gas supply costs between the two cases (and the resulting differences in field and end use prices), lead to appreciable variations in North American energy demand, fuel shares by end users, Canadian gas export levels and fuel choices by electric utilities.

Following the Export Impact Assessment Workshop conducted in April, 1993 the Board decided to integrate its analysis of the long-run impact of incremental natural gas exports with analysis conducted for this report[4]. To fulfill this commitment we include an analysis of the impact on Canadian gas markets of a substantial increase in U.S. demand for natural gas relative to the two cases described above.

Further, there is increasing interest in the implications for Canada of potential natural gas imports into the U.S. from Mexico or from other new sources of low cost gas supplies. We have, therefore, analyzed the implications for North American natural gas markets, and specifically for Canadian exports, of the introduction into the North American market of a new, low-cost, source of supply.

Turning to oil, world oil markets have been characterized in recent years by a tendency for prices to drift downward and for expectations about future prices to be lower than previously held views. Thus controlling the costs of finding and producing oil from Canada's relatively high cost conventional and oil sands resources has become critical to the success of the Canadian upstream oil industry. At the same time there have been a number of technological developments in oil production which have tended to reduce the costs of

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4 National Energy Board, *Export Impact Assessment*, letter to Interested Parties, 26 August 1993.

TABLE 1-1
Framework of Analysis[1]

Issues	Scope
Two Main Cases	
1. Current Gas Supply Technology ("Current Tech") – supply costs increase as new reserves are found and developed	Comprehensive for all supply sectors and energy demand
2. High Gas Supply Technology ("High Tech") – supply cost increases are mitigated by technological change	Comprehensive for all supply sectors and energy demand. Includes a high technology assumption for oil supply.
Extended Analysis	
3. More energy-intensive economy ("Alternative Macro")	Energy demand
4. Enhanced inter-utility cooperation ("Enhanced Cooperation")	Electricity supply
5. Export Impact Assessment – higher U.S. gas demand	Natural gas supply, demand and prices
6. Additional low-cost gas supply	Natural gas supply, demand and prices
7. High and low oil prices (US$30 and US$15 per barrel)	Oil supply

1   Unless indicated otherwise prices and costs are expressed in constant 1993 Canadian dollars.

producing those resources. Such developments include horizontal, multiple-leg wells and a number of technologies aimed at reducing the costs and improving the recovery of oil in place, particularly heavy oil resources. Recognizing that the impacts of these emerging technologies are relatively speculative at this time, we have assessed the implications for Canadian oil supplies of alternative rates of development and use of such technologies. We have also analyzed the implications for Canadian oil supply of relatively low and high future oil price tracks.

For electricity, there is increasing interest in the prospects for enhanced cooperation and trade across traditional utility franchise areas in both Canada and the U.S. The potential benefits from such cooperation and trade were analyzed by the Board pursuant to a request from the Minister of Energy, Mines and Resources in a report which has recently been released by the Minister[5]. We have pursued this analysis by assessing the implications of enhanced inter-utility trade for the nature and geographical distribution of generating capacity and related atmospheric emissions.

The demand for energy is strongly influenced by the structure of economic activity, in particular by the share of economic activity accounted for by the production of energy-intensive commodities relative to less energy-intensive goods and services. Over the past two decades the production of services has been rising relative to the production of goods in Canada as in other industrial countries. However, it is far from clear that this trend will continue. In fact a number of factors, including the relative curtailment of government services, have at least temporarily reversed this trend. We have therefore analyzed the implications for energy demand in Canada of an economic structure which evolves more strongly in the direction of the production of goods than it has in the recent past.

Subsequent chapters in this report outline the principal findings of our analysis and relate them to previous findings. Where possible, we also compare our results to the conclusions and views of other analysts.

---

5   National Energy Board, *Review of Inter-Utility Trade in Electricity*, January 1994.

Chapter 2

MACROECONOMIC ASSUMPTIONS

To provide a context for an assessment of energy futures, a view of the prospects for international and domestic economic activity is required. For Canada, our approach was to develop this context on the basis of mid-range, roughly consensus, views about the determinants of long-run future economic growth. The major determinants of long-run economic growth for an industrialized economy are the rate of labour force growth, the rate of capital accumulation and the rate of growth in productivity attributable to other factors such as technological change. Over the long run, an economy will tend to grow at a rate close to the sum of the rates of growth of these determinants, a rate that can be described as the potential rate of growth. Short-run cyclical variations occur but the importance of these for the annual average growth rate diminishes over a period as long as 20 years.

The macroeconomic assumptions were generated in the context of current policies on the part of the Canadian and other governments worldwide. They represent assumptions made to facilitate our energy supply/demand analysis. This set of assumptions should not be interpreted as a forecast.

Most consultees favoured use of middle-of-the-road economic assumptions of the sort which we have made. Some others suggested that we should directly address the issue of sustainable development. A few suggested we include a zero economic growth case. We recognize the interest in such cases but we have not developed them for this report.

Global Economic Context

A multitude of issues and uncertainties have a bearing on the future of the global economy. Among the major ones are: prospects for political stability and economic development in eastern Europe and the territories of the former Soviet Union; population growth and rates of development in India, China and on the African continent; the effects of NAFTA and, more broadly, prospects for trade liberalization with and among North and South American economies; growth prospects for Japan and the "Asian tigers"; and trade liberalization, immigration and slowing natural population growth in the OECD area. For the first time in many years, the future course of world crude petroleum prices is not considered a critical factor in establishing the macroeconomic assumptions.

In spite of this imposing list of issues, many analysts, including those we consulted, have adopted similar views about the future course of the world economy:

- Growth in the OECD area slows to an average annual growth rate near 2.5 percent from the average over the past 20 years of nearly three percent. Slowing growth is expected particularly in Europe and Japan.

- The U.S. economy is generally expected to show average annual real output growth of about 2.5 percent over the long term, with moderate inflation and relatively low nominal interest rates.

- Growth rates increase among the "Asian tigers" with China joining and perhaps even leading.

- There is hope for the resolution of problems in Russia and in the other areas of the former Soviet Union with growth re-emerging before the year 2000.

These assumptions correspond closely to the view of the IEA/OECD secretariat.

The Canadian Economy

Since the early 1970s, there has been a slowing of potential growth in Canada reflecting declining population growth and little growth in productivity. The range of views relating to future economic performance can be seen in Table 2-1.

Most demographic projections show population growth of just over one percent per year with household formation proceeding somewhat more rapidly as a consequence of relatively high rates of immigration and a trend to smaller households. Our projection adopts this view: the fertility rate, the average number of children born per woman over her lifetime, is assumed to remain near its present level of 1.8, somewhat below the population replacement rate. Net immigration, generally following most-recent trends, is assumed to average 150 000 per year over the final decade of the projection period, somewhat lower than recent levels but high in the longer-term historical perspective. Labour force participation is assumed to increase only modestly over the projection period, reflecting a continued but slower

rate of increase in the participation rate for adult women and a further decline in the rate for older men.

There is some disagreement with respect to the prospects for productivity growth in Canada, but most analysts expect it to improve from the low level experienced, on average, over the past 20 years. Such an improvement would reflect the effects of a number of policy developments worldwide, including continuing trade liberalization. The most common view is for growth to average about one percent annually in the period to 2010 although some believe the improvement will be even greater. The DRI view achieves an annual average RDP growth rate about half a percentage point higher than the other projections on the basis of stronger growth in productivity.

There is some allowance in our projection for the Canadian economy to take up the slack resulting from the 1990-1992 recession. The take-off point for the current projection is close to the trough of a cycle; the unemployment rate in 1993 was over 11 percent, well above the rate which consultees regarded as reasonable on average over the longer term.

Inflation is moderate, in the range of two percent per year, in all projections. At the time the macroeconomic projection for the supply/demand report was made the Canada/U.S. exchange rate stood at US$0.79 for one Canadian dollar and this rate was chosen as the assumption for the macroeconomic projection. The assumption is also consistent with the fact that no sustained differences are expected between the U.S. and Canadian inflation rates.

The Goods/Services Mix

The distribution of total output between goods and service industries in the Canadian economy is important to the analysis since different distributions of output have important implications for energy requirements. The production of goods is much more energy-intensive than the production of services. Over the past 20 years, service sector growth has been more rapid than growth in the goods sector and the share of service industries in total output has increased (Table 2-2).

The relative expansion of the service sector, historically, reflected such factors as: an increasing tendency for households to purchase services as women's labour force participation increased; an expansion of public health services and education; and an increasing tendency for businesses to contract-out for some types of business services. Within the service sector, there has been a slowing in the growth of non-business services as a result of a relative contraction of the government sector.

There is considerable uncertainty with respect to the future evolution of the balance between goods and service industries over the projection period. There are two competing views:

- The trend towards an increased service sector share (a lower goods sector share) will continue,

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TABLE 2-1

Comparison of Canadian Macroeconomic Projections: 1991 to 2010[1]

Average Annual Growth Rates (percent)

	NEB	NRCan	Informetrica	WEFA	DRI
RDP	2.5	2.5	2.6	2.6	3.0
Households	1.6	1.5	1.6	N/A	1.5
Labour Force	1.3	1.2	1.2	1.3	N/A
Unemployment Rate (percent in 2010)	7.4	7.9	9.0	7.2	7.8

1. These projections were current at the time our macroeconomic projections were developed. Some of these organizations may have subsequently changed their views.

Source: Compiled by NEB staff

reflecting the aging of the population leading to increased demand for health care and consumer services such as tourism; a continued increase in the adult female participation rate; and, growth in information-based industries.

• The trend to a lower goods sector share will slow or perhaps even reverse. This change in trend could occur as a result of developments such as trade liberalization. Trade liberalization could have a more favourable impact on goods than services exports because of Canada's comparative advantage in the production of resource-based goods and in some secondary manufacturing industries. Also favouring an increased goods share in the economy are the implementation of the GST which improved the cost competitiveness of Canadian goods in both domestic and export markets; fiscal restraint which will further reduce growth in the government sector; and, lower demand for education services because of the aging of the population.

In both of our sets of macroeconomic assumptions, the historical trend reverses and the goods sector grows faster than the rest of the economy. This reflects a continued slowing of growth in government services but also a rebound in goods sector activity during the recovery from the 1990-1992 recession. In the reference projection, however, the share of service industries within the business sector again expands post-2000 following the recovery phase of the economy. This reflects the continuing influence of factors which resulted in the increasing share of business services over the previous two decades.

The alternative macroeconomic projection features stronger growth in the goods sector, particularly in energy intensive industries. It was developed to evaluate the importance of the uncertainty about economic structure for energy demand. To ensure that the impact of the change is limited to the change in economic structure, growth in domestic production is the same in both sets of macroeconomic assumptions.

TABLE 2-2
Evolution of the Goods/Services Mix – Sector Shares
(percent)

	Goods Sector		Service Sector					
			Business Services		Non-business Services[1]		Total Services	
1962	35.8		41.7		22.5		64.2	
1973	39.3		39.8		20.9		60.7	
1981	30.0		50.6		19.4		70.0	
1991	27.3		54.3		18.4		72.7	
Projection								
	Ref[2]	Alt[3]	Ref	Alt	Ref	Alt	Ref	Alt
2000	28.5	29.7	54.8	54.7	16.7	15.6	71.5	70.3
2010	28.8	31.6	56.0	54.6	15.2	13.8	71.2	68.4

1 The non-business sector is largely composed of the government sector but it also contains religious and charitable institutions and non-profit organizations.
2 Reference case assumptions
3 Alternative Macro assumption

Source: Statistics Canada, Informetrica and NEB

Regional Economic Performance

Regional economic growth over the projection period follows a pattern similar to provincial population and labour force growth. Over the last fifteen years, in every province the labour force grew substantially faster than population because of increased female participation in the workforce. We expect a slowing of this trend and, therefore, labour force growth which more closely mirrors population trends (Table 2-3).

Population and labour force growth in Atlantic Canada are projected to be the slowest in the country because of continued high levels of inter-provincial migration, low levels of international immigration and low birth rates. The net effect of very weak demographics, average labour productivity gains, heavy reliance on primary industries such as fishing and a low proportion of manufacturing and export-oriented industries leads us to project economic growth in Atlantic Canada at a rate well below the national average.

Québec's population and labour force are assumed to grow more slowly than the national average despite government efforts to encourage higher fertility rates and immigration levels. Labour productivity on the other hand is projected to grow slightly faster than the

Canadian average because of strong growth in the manufacturing sector with the net result of a growth rate just below the national average.

Ontario displays the strongest rate of growth over the recovery period and throughout the entire period of the analysis. This reflects two main factors:

• Ontario has traditionally been among the premier destinations for both international and inter-provincial migrants, primarily because of the availability of employment opportunities.

• Ontario was the province most severely affected by the 1990-1992 recession and therefore has the largest output gap to close.

Productivity also increases rapidly because of rationalization and restructuring in the manufacturing sector.

Manitoba has historically been one of the more balanced economies in Canada; its economic structure closely matches that of the country as a whole. The Manitoba economy is projected to grow somewhat more slowly than the national average as good productivity growth is offset by slow population growth and weak agricultural sector performance.

TABLE 2-3
Key Economic Variables by Province
Average Annual Growth Rates (percent)

1976 – 1991

	Atl	Qué	Ont	Man	Sask	Alta	B.C.
RDP	2.3	2.1	2.5	1.7	2.1	1.9	2.7
Population	0.4	0.7	1.3	0.4	0.5	2.2	1.9
Labour Force	1.8	1.6	2.1	1.3	1.4	3.0	2.7

1991 – 2010

	Atl	Qué	Ont	Man	Sask	Alta	B.C.
RDP	1.7	2.3	2.9	2.1	1.6	2.3	2.9
Population	0.3	0.8	1.4	0.7	0.7	1.3	1.7
Labour Force	0.5	0.9	1.6	0.8	0.6	1.5	1.9

Source: Statistics Canada, Informetrica and NEB

Saskatchewan is very dependent on the primary industries of agriculture and mining, the long-term prospects for which are perceived to be less than favourable. This economic structure combined with weak population and labour force growth is projected to result in economic growth well below the national average and about equal to that projected for Atlantic Canada.

In Alberta, net migration has fallen from the rates experienced during the oil boom years. This recent trend is expected to continue, resulting in much slower population growth over the next 20 years than experienced during the past two decades. The effect of lower population growth on the labour force is partially counter-balanced by the fact that the population is younger than the national average. The service sector is assumed to grow faster than the mining sector over the projection period, moderating growth in labour productivity. On balance, the Alberta economy is projected to grow at a rate slightly below the national average.

British Columbia's population and labour force should exhibit the strongest growth in the country, buoyed by the continuing trends of high international and inter-provincial migration as people are attracted by the province's agreeable climate and economic opportunities. Growth in the provincial economy is projected to match that of Ontario and to be above the national average.

ENERGY PRICES

The price of energy is particularly important to Canadians because of Canada's climate and because an important part of Canadian industry is energy intensive; high energy costs can be a handicap. On the other hand, Canada has a large energy-producing sector so energy prices and the profitability of energy production have important implications for economic activity and employment in the major energy producing regions. For energy producers, the prices which are important are wellhead or fieldgate prices while for consumers, the relevant prices are for delivered energy. Final consumers of energy have choices among various energy commodities to satisfy their needs. Their choices depend on the relative prices of these commodities at the burner tip.[1]

This chapter describes the price levels and changes which either emerge from our analysis or have been assumed. Wellhead or producer prices are presented first, beginning with the international price of crude petroleum, and concluding with a discussion of prices to end users at the burner tip.

Prospects for International Crude Petroleum Prices

Although the energy sector is important to the Canadian economy, Canadian production and consumption of crude petroleum are small in the context of the global market. Consequently, Canada is a price taker for crude oil. In considering the prospects for crude petroleum markets to the year 2010, recent developments must be put in the context of longer-term considerations and trends. Over the past century and a quarter, the price of crude has generally varied within a range US$10 to US$20 in 1993 dollars (Figure 3-1). Although at times the market for crude petroleum has not been particularly competitive, market forces have played a major role in keeping crude prices within this relatively narrow band.

In the period from 1973 to the present crude oil prices have been more volatile than they had been for many years. The volatility has reflected political events including periodic instability in some of the major producing regions and actions by OPEC. Markets have also been affected by the more gradual but equally powerful influences of the operation of market adjustment mechanisms. It appears that, recently, technological progress has tended to reduce the supply costs and prices for crude petroleum.

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1 Because consumers use energy for the tasks which it performs, such as heating a house, consumers make their decisions based on both the price of an energy commodity and the efficiency with which it performs a specific function.

FIGURE 3-1
Crude Oil Prices
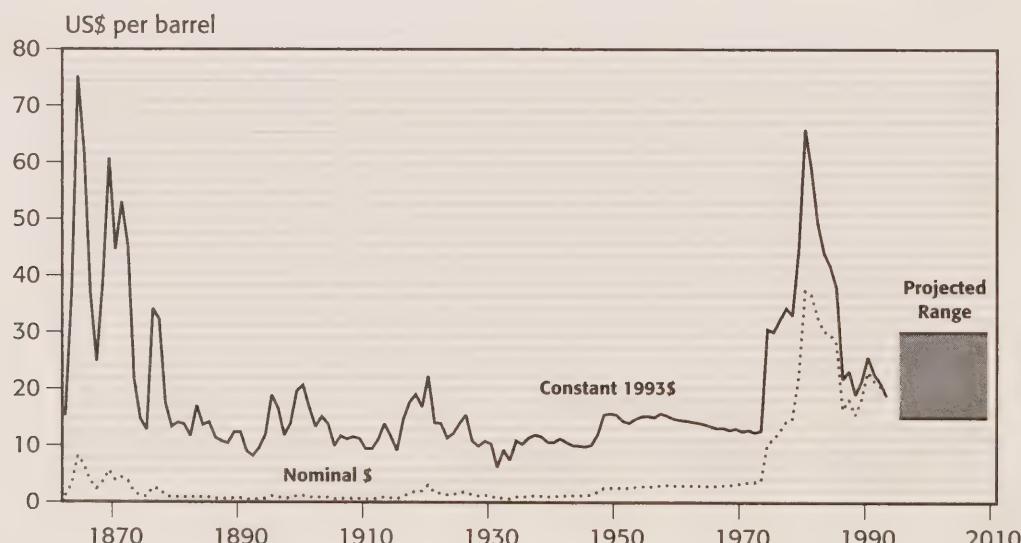
Clearly, one cannot expect to project the course of crude oil prices with any accuracy. However, as the historical experience suggests, crude prices can generally be expected to fall within a range conditioned by market fundamentals. These include rates of economic growth and the associated implications for energy demand, technological change affecting supply costs of crude oil and competing fuels, and changes in consumer preferences.

As in the 1991 report, our approach is to provide an estimate of the "sustainable range" for future crude petroleum prices based on the underlying fundamental forces affecting supply and demand. The actual price of crude will, of course, fluctuate and could lie outside the estimated sustainable range from time to time even if our analysis is generally correct. For example, the price could fall below the bottom of the range for some time depending on the reaction of OPEC and other market participants to the return of Iraqi production to world markets.

The analysis presented here is based on supply costs of crude petroleum in the Middle East and the rest of the world. Given the large amount of crude thought to be available at supply costs of less than US$30 (1993 dollars), we believe that, under any plausible outcome for world crude oil demand, the conclusions of an analysis based on supply costs and OPEC behaviour alone are likely to be valid.

Estimates of crude petroleum supply costs have declined over the past few years, in part because of technological improvements such as horizontal drilling, three-dimensional seismic, and advanced off-shore production systems, but also because of recent successes in cost cutting by producers in the face of lower prices. Of particular importance are cost reductions in areas of non-OPEC supply since the marginal cost of these producers limits OPEC's market power.

Table 3-1 presents estimates of supply costs for world oil reserves developed by Petroleum Economics Limited (PEL). Although specific to PEL, views expressed during our consultation process were consistent, at least qualitatively, with these estimates. There are a number of key messages to be obtained from the data. Most importantly, oil reserves are very large: it is estimated that there are 2.4 trillion barrels of world reserves of crude petroleum which can be profitably produced at prices no greater than US$25. At 1993 levels of world consumption, this implies a reserves life index of 100 years.

Within the Middle East alone, there are over one trillion barrels of oil that can be profitably produced at today's prices. Indeed, the PEL estimates suggest that 75 percent of the proven and probable reserves in the Middle East can be profitably exploited at prices of less than US$5. Unfettered competition among the members of OPEC could produce very low prices, perhaps as low as US$5 per barrel for an extended period of time. Therefore, any analysis which contemplates prices significantly higher must be based on the assumption of some degree of cohesion in OPEC.

Although 75 percent of the 1.8 trillion barrels of proven and probable reserves outside the Middle East can be profitably exploited at prices below US$25, most of this non-OPEC supply has a supply cost above US$15. At prices below US$15, competition from non-OPEC production would not be particularly important. Further, OPEC revenue requirements appear to provide a strong incentive for OPEC to manage supply so as to obtain a price of at least US$15.

At prices of US$25 and above, competition from non-OPEC sources of supply would greatly weaken OPEC's market power. Our analysis suggests that the Canadian oil sands resource can be profitably exploited at prices below US$25. Initiatives by consumers and

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TABLE 3-1

Supply Costs of Proven and Probable Crude Oil Reserves

Supply Costs (US$1993/bbl)	Middle East	Other (billion barrels)	World
<14	1055	270	1325
14 to 25	–	1065	1065
>25	–	455	455

Source: Petroleum Economics Limited and NEB

governments to improve energy efficiency and to substitute other fuels would also be important at these prices.

The data and analysis presented here suggest that a price ranging between US$15 and US$25 could be sustainable depending on the strategy and cohesiveness of OPEC. Other analysts tend to be in general agreement with this assessment. However, the analysis of a few observers, most notably the International Energy Agency and the Energy Information Administration in the United States, present a somewhat higher upper bound for crude prices, suggesting a somewhat different view of non-OPEC supply costs.

The lower bound of the range of views we surveyed corresponds closely with the US$15 suggested by our analysis but the upper bound lies closer to US$30 than to US$25. Consequently, we have adopted a "sustainable range" of US$15 to US$30 for use in the analysis of price sensitivity of Canadian crude oil supply. All other quantitative analysis done for the report assumes a mid-range price which rises from the 1993 average of US$19 to US$23 over the course of the projection period.

Natural Gas Fieldgate Prices

Prior to signing of the Western Accord in March 1985, natural gas prices in Canada were regulated. Since that time, Canadian natural gas prices have been increasingly determined by market forces in North America. We projected Canadian natural gas fieldgate prices by examining both supply and demand conditions for natural gas within the North American context.

As discussed in more detail in Chapter 6, below, we developed two main cases corresponding to two views about the evolution of natural gas supply costs: a Current Tech case, based on an analysis similar to that contained in previous reports, in which natural gas supply costs increase steadily over our study period, and a High Tech case, in which unspecified technological improvements act to keep supply costs near current replacement levels in real terms. Figure 3-2 shows the resulting projections of Canadian natural gas fieldgate prices.

In the Current Tech case, Canadian fieldgate prices rise from $1.58 per gigajoule in 1993 to about $4.00 per gigajoule (1993 dollars) by the end of the projection period, an average annual increase of six percent. In the High Tech case, fieldgate prices rise much less rapidly, at an average annual rate of two percent over the projection period, to reach about $2.25 per gigajoule by 2010.

Electricity Prices

Over the last 20 years, electricity prices in all regions of the country have increased more rapidly than the general price level. In the last few years, several Canadian electric utilities have experienced problems with over-capacity: generation capacity was added in the latter part of the 1980s based on demand projections that did not materialize. The existence of this excess capacity had the potential to produce significant rate increases but many utilities have recently engaged in major cost reduction exercises to keep rates down.

With the exception of price increases that have already been announced by utilities, electricity prices in

FIGURE 3-2
Canadian Natural Gas Fieldgate Prices
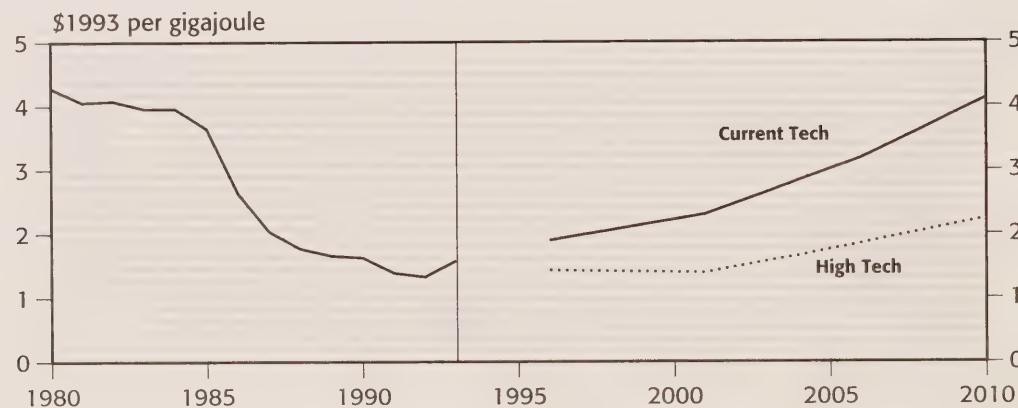
all regions and all sectors are assumed to remain constant in real terms throughout our study period. This is the same approach used in the 1991 report. Rising electrical loads during the economic recovery should help to reduce unit costs. Further, supply cost data received from the utilities are generally consistent with constant, real prices in the future even when additions to capacity are required. In general, base load capacity additions are not expected to be required until the latter half of the projection period.

Coal Prices

Following consultation with the industry, we assumed a real price of coal which rises very slightly over the projection period – at an annual average rate of 0.5 percent. This increase is much lower than the rates of increase in the prices of competing fuels. Inter-fuel competition and undesirable environmental properties in combination with abundant supply should act to maintain a low coal price environment.

Alternative Energy

We use the term alternative energy to refer to non-conventional and/or renewable sources – such as wood, wood wastes, solar, small-scale hydro and wind, and municipal solid waste.

In 1992, these sources accounted for just under seven percent of Canada's end use energy requirements.

Of the total 489 petajoules of alternative energy, just over 80 percent, or 395 petajoules, was wood waste used in the pulp and paper and forestry sectors, 19 percent represented wood use in the residential sector, while other sources accounted for under one percent.

Measuring use of alternative or renewable energy in the residential and commercial sectors poses certain difficulties. In some instances, wood or solar may not be the primary source of energy. Use of passive solar or infrequent use of wood may be measured as conservation (it reduces requirements for conventional, measured energy sources) rather than as alternative energy consumption. Thus it is likely that our estimates understate the use of some of these alternative energy forms, although their impact on the use of conventional non-renewable energy sources is captured in our projections.

Like other energy forms, demand for alternative energy will be influenced by its prices relative to those of competing energy sources. For our assessment of the potential growth in the use of alternative energy we gathered data on the estimated supply costs of alternatives and compared those costs with today's prices of conventional energy forms (Table 3-2).

The costs of alternative energy are estimated on a commercial basis to make them comparable with the prices of conventional energy. That is, these estimates take no account of the potential environmental costs

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TABLE 3-2
Costs of Alternative and Conventional Energy[1]
($1993 per gigajoule)

Energy Source	Applications	Supply Cost[2]
Wind	Electricity Generation	14-28
Active Solar	Heating	6-33
Biomass	Heating	3-42
Photovoltaics	Electricity Generation	150-460

Energy Source	Applications	Burner Tip Price[2]
Natural Gas	Residential Sector	6-12
Electricity	Residential Sector	15-20
LFO	Residential Sector	16-18

[1] The range represents the lowest and highest cost and price in Canada.
[2] Efficiency-adjusted supply costs and burner tip prices.

Source: Supply costs, NRCan
         Burner tip prices, NEB

associated either with conventional energy or alternative forms. Such environmental factors consist, for example, of carbon dioxide emissions or of the environmental degradation that could result from the construction of a large hydro dam. If energy forms were to be priced on a basis which included their environmental costs then the relationship between the prices of conventional and alternative energy forms could well be different from those shown here. We use the market or commercial pricing approach because our objective is to assess energy supply and demand in the context of anticipated market price behaviour.

There is a wide range of prices and costs for both conventional and alternative energy forms. In the case of conventional energy the prices differ dramatically depending on the geographical location at which they are measured. In the case of natural gas this is related to the fact that transportation costs are much higher for eastern markets than for service to western markets. In the case of electricity, generating costs differ widely across the country depending on the type of installed generation capacity. There is an even wider range in the estimated end use costs of alternative energy sources which are highly site and use specific. The low end of the cost ranges shown in the table represent the most favourable application of existing technologies; these are projects which are located in resource-rich sites and, in the case of electricity applications, which are close to the electrical grid.

Clearly some alternative energy forms are competitive with conventional sources and are now being used, in some cases quite extensively. As noted, much of the alternative energy currently being consumed is in the form of wood and wood wastes used for residential purposes and in the pulp and paper industry respectively.

Except for wood and wood waste most alternative energy sources are in general still expensive compared with conventional energy, when priced on a market basis. Over our study period, however, pricing mechanisms and tax policies could change, as could individual preferences in favour of using alternative energy forms. Technological progress could also enhance the commercial viability of alternative energy.

Transportation and Distribution Costs

Transportation costs can be a major part of the cost of delivered energy. This is particularly true for natural gas and electricity, which are both expensive to transport. Over the past 20 years, most of the variation in delivered energy prices has been due to changes in taxes and wellhead prices rather than to changes in transportation costs. We assumed, in the analysis conducted for this report, that the costs of transportation and distribution of energy commodities will remain constant in real terms.

In the case of natural gas, burner tip prices include transportation and distribution costs and taxes in addition to the fieldgate price. Transportation costs are much lower and represent a smaller proportion of the burner tip price for consumers located close to supply sources. Distribution costs vary among provinces, within individual provinces and by end user. For example, in the industrial sector in 1991, transportation and distribution charges constituted only 21 percent of the burner tip price in Alberta but 75 percent in Québec (Figure 3-3).

For electricity, transmission and distribution costs make up between about 25 and 35 percent of the delivered price of electricity depending on the utility.

Burner Tip Prices[2]

Burner tip prices differ significantly between sectors and among regions. Figures 3-4 through 3-7 show the historical and projected evolution for end use prices in Ontario and British Columbia in the residential and industrial sectors.

Most petroleum product prices, including light fuel oil (LFO), motor gasoline and diesel fuel, increase more slowly than the price of crude oil in all sectors and all provinces. A premium was added to heavy fuel oil (HFO) prices as a way of accounting for the costs of switching from natural gas in the industrial sector. This reflected the views expressed at the Export Impact Assessment (EIA) workshop and in our consultation process that the costs of switching could be high because of the need to build infrastructure and to meet environmental standards. Electricity prices at the burner tip show no increases except as already announced by utilities.

The most interesting part of the price story relates to end use prices for natural gas, which differ between the Current Tech and High Tech cases. In the latter case natural gas prices rise only moderately over the projection period.

Relative to electricity, gas remains the least-cost fuel in all provinces where it is available, even in the

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2   The relevant prices for analysis of energy demand are prices at the burner tip adjusted to reflect differing fuel efficiencies. This adjustment is required to derive the actual per-unit costs of energy services to end users. The prices shown in Figures 3-4 through 3-9 are adjusted for efficiencies.

Current Tech case, and has a substantial competitive advantage under the High Tech assumptions. This is illustrated for the Québec residential sector in Figure 3–8. HFO and gas are much cheaper than electricity in all cases. Gas becomes a high-cost alternative to HFO under the Current Tech assumptions by about 2005 (Figure 3-9). HFO would have been cheaper than gas throughout most of the projection period had we not added a premium to the price of HFO.

In Atlantic Canada, natural gas is not available at present and interfuel competition is confined to electricity and LFO in the residential sector. Under our assumptions LFO remains cheaper than electricity throughout the projection period.

FIGURE 3-3 (a)
Composition of Natural Gas Price in 1993 – Alberta

$1993 per gigajoule

Legend: Distribution and Taxes / Transportation / Fieldgate

Residential   Commercial   Industrial
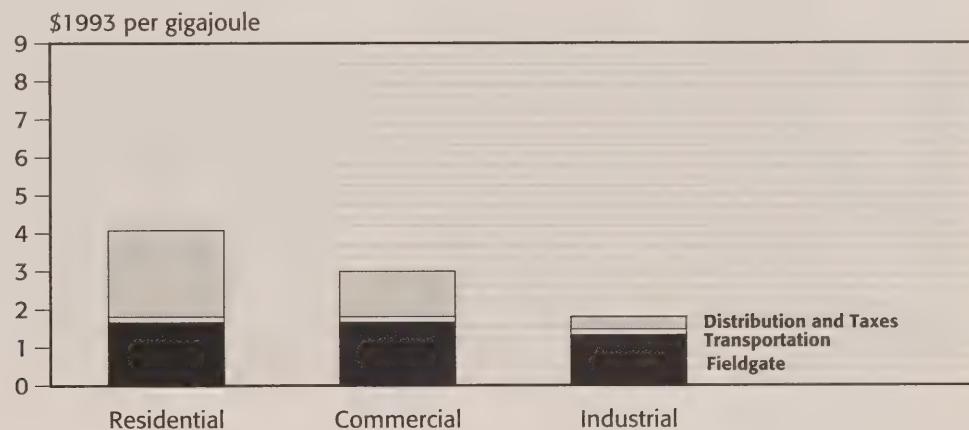
FIGURE 3-3 (b)
Composition of Natural Gas Price in 1993 – Québec

$1993 per gigajoule

Legend: Distribution and Taxes / Transportation / Fieldgate

Residential   Commercial   Industrial
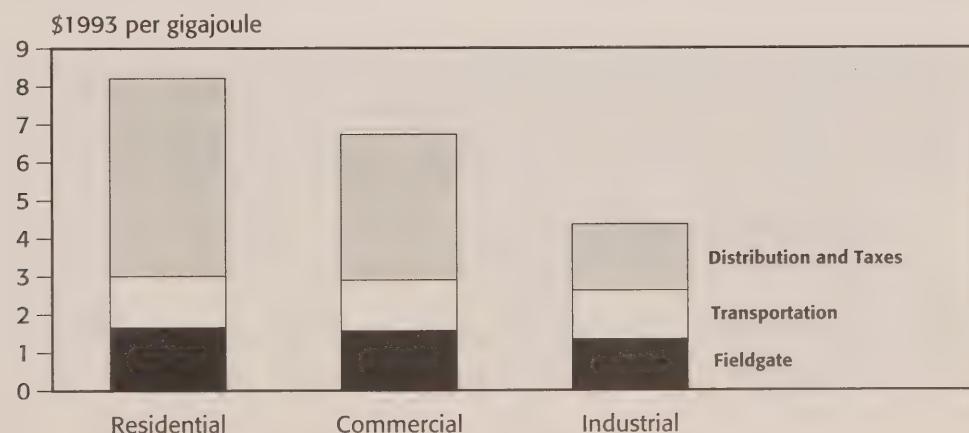
FIGURE 3-4
Residential Energy Prices – Ontario

$1993 per gigajoule

Electricity
LFO
Gas-CT
Gas-HT

1980   1985   1990   1995   2000   2005   2010
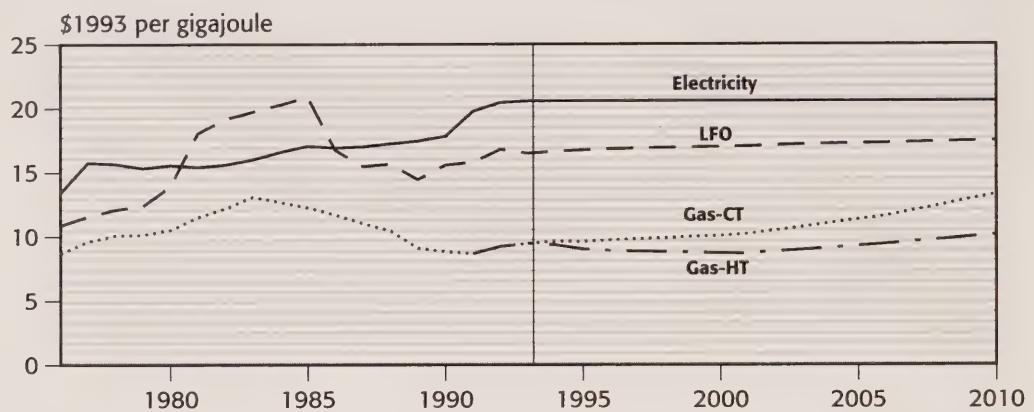
FIGURE 3-5
Residential Energy Prices – BC

$1993 per gigajoule

LFO
Electricity
Gas-CT
Gas-HT

1980   1985   1990   1995   2000   2005   2010
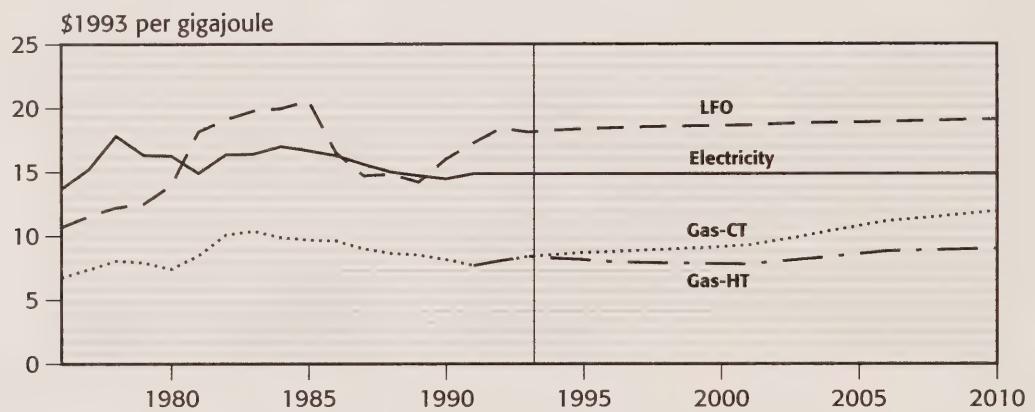
FIGURE 3-6
Industrial Energy Prices – Ontario

$1993 per gigajoule

Electricity
Gas-CT
HFO
Gas-HT

1980   1985   1990   1995   2000   2005   2010
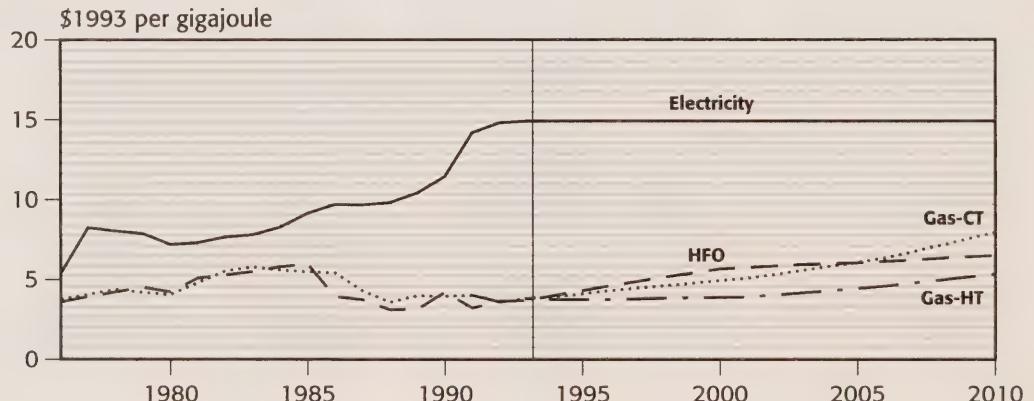
FIGURE 3-7
Industrial Energy Prices – BC

$1993 per gigajoule

Electricity
HFO
Gas-CT
Gas-HT
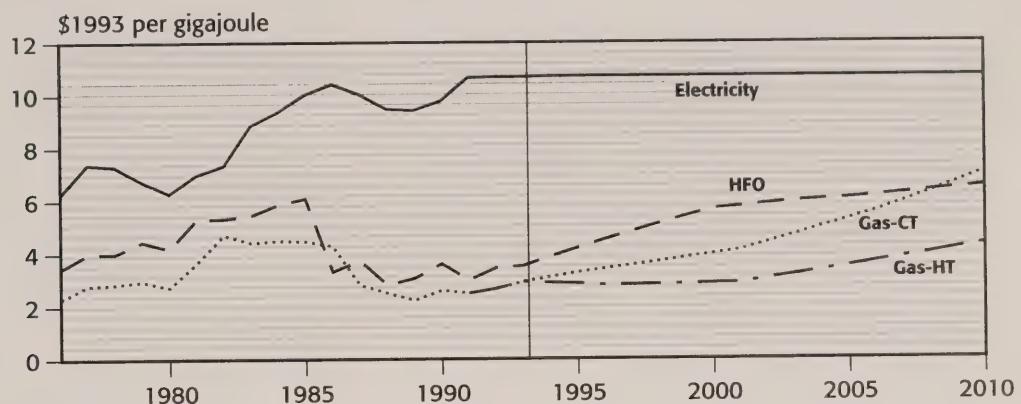
FIGURE 3-8
Residential Energy Price Ratios – Gas to Electricity, Québec

Current Tech
High Tech
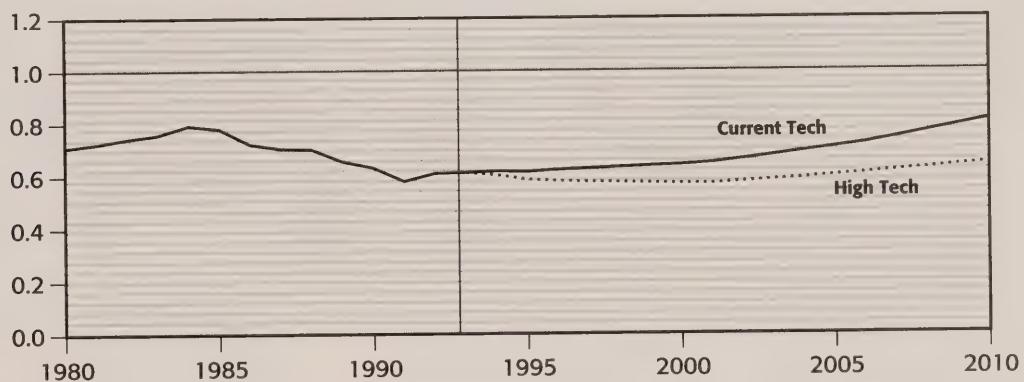
FIGURE 3-9
Industrial Energy Price Ratios – Gas to HFO, Ontario

Current Tech
High Tech
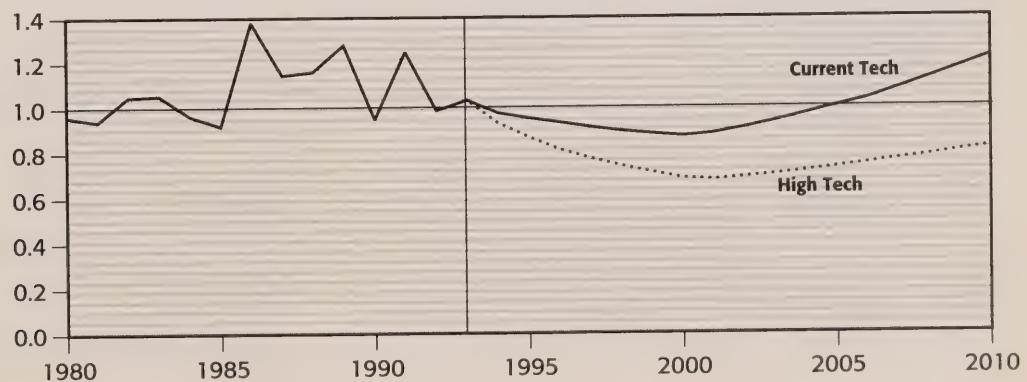
CANADIAN ENERGY DEMAND

Energy commodities are rarely used as final products. Rather their energy content is used to perform other functions, such as space heating, powering motors for industrial processes or automobiles for transportation. As such, energy use, or demand, derives from the use of other goods and services.

Thus energy demand depends on the level and structure of economic activity, demographics, energy prices, the efficiency of energy use (which in turn is related to the characteristics of energy-using equipment and buildings), related government policies and the nature of consumer tastes and behaviour.

Prior to the early 1970s, energy demand increased rapidly as the economy grew strongly and energy prices were low (Figure 4-1).

Since the oil price shock of the early 1970s, energy use patterns in all major industrialized countries have changed dramatically. There have been major shifts off oil and conservation measures have been adopted to reduce oil and other energy use through improved energy efficiency. Consumers of energy began to focus more on conservation and, in response, equipment manufacturers made improvements in the energy efficiency of appliances and industrial machinery. Government policy, motivated by concerns for security of energy supply, enhanced these efforts through the introduction of "off-oil" and energy conservation programs in the late 1970s and early 1980s. The slower economic growth which characterized the post-1973 era, including two deep recessions from 1981 to 1982 and 1990 to 1992 also dampened growth in energy use.

Some of the impact of these factors occurred fairly quickly as a result of behavioural changes such as the lowering of thermostats. However, the full impact of higher prices and changed policies on energy consumption occurs only over a much longer period of time as newly-designed, more energy-efficient, buildings, machinery and appliances gradually replace existing equipment.

Even after allowing for the effects of fluctuations in economic activity, there appears to have been a change in the trend rate of growth of energy use in Canada over the past two decades. The average annual rate of growth of end use energy demand in the 1980s (0.8 percent) was about one third that of the 1970s (2.6 percent). The change in trend was a result of a number of factors including the ongoing effect of the large energy price increases of the 1970s and slower growth in the economy, population and the number of households.

The change in trend has also resulted in a change in the relationship between energy use and economic activity. Figure 4-2 shows the recent evolution of the intensity of energy use in Canada, i.e. the amount of energy used per unit of Gross Domestic Product[1].

Energy intensity declined more rapidly in the 1980s than in the 1970s. A major question for analysts of the energy demand outlook is whether the trend in the future will be more like that of the 1980s or of earlier decades. Clearly the intensity of energy use will be influenced in the future, as it has been in the past, by energy prices, demographic developments, technological change and, importantly, by consumer and industry preferences about the acquisition and use of appliances and machinery. These issues are discussed more extensively below.

There are, however, certain features of the response to the energy price shocks of the 1970s and 1980s which have permanently changed the relationship between economic activity and energy demand. Today's energy-using equipment differs greatly from that of the early 1970s:

- The thermal efficiency of both existing and new buildings is much higher and building codes ensure that there will not be a reversion to previous, less efficient, standards.

- Energy-using equipment, be it household appliances or industrial machinery, is more efficient and efficiency standards have been introduced which will lead to even further improvements.

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1 Energy intensity is not a measure of the efficiency of energy use. Changes in it reflect not only changes in efficiency but also other factors such as shifts in economic activity from one industry to another (because different production processes require quite different amounts of energy use per unit of production), changes in consumer preferences (a large car requires more energy than does a small car even though the efficiency of the engines may be similar). This distinction between efficiency and intensity is frequently ignored when international comparisons of energy use are made. For a number of reasons – distance, climate, the nature of the economy – Canada uses much more energy per unit of output than many other countries but this is not necessarily indicative of the efficiency of energy use in specific tasks.

As noted, however, consumer attitudes and behaviour with respect to the acquisition and use of energy-using equipment, as reflected, for example, in the purchase of smaller, lower powered vehicles, remain major uncertainties which can have large impacts on energy use.

Increasing use of integrated resource planning among electricity and natural gas local distribution companies is also beginning to influence the demand for energy. Using this process, utilities assess the cheapest means of supplying customers with the services deriving from energy use such as space heating or lighting. This may involve using demand side management programs to pay consumers to install devices such as more insulation or more efficient light bulbs so that required levels of warmth and light are provided using less energy.

We have incorporated an allowance for the effect of demand side management programs on electricity; the practice is not yet widespread in natural gas utilities. Estimates of electricity savings were developed in consultation with electric utilities. Projected electricity demand was adjusted downwards by some 120

FIGURE 4-1
**Canadian End Use Energy Demand**
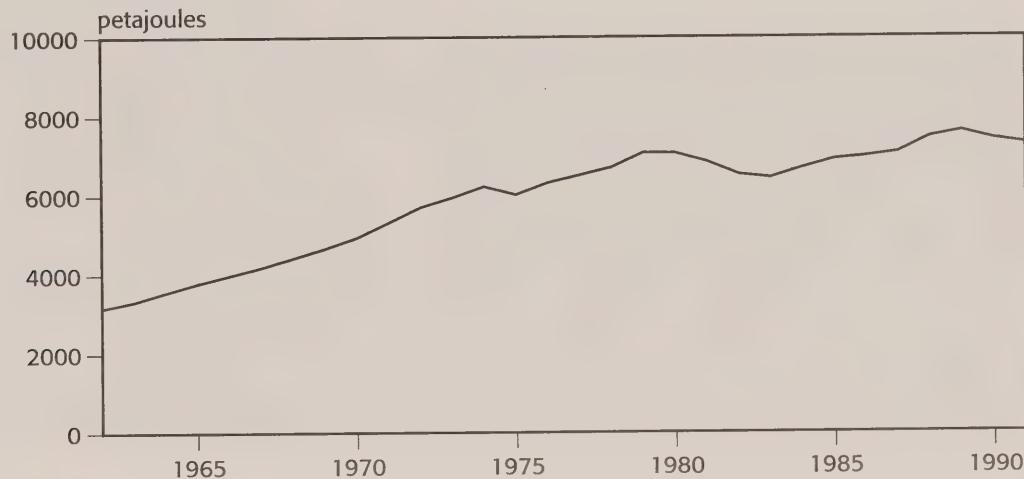
FIGURE 4-2
Canadian End Use Energy Intensity*
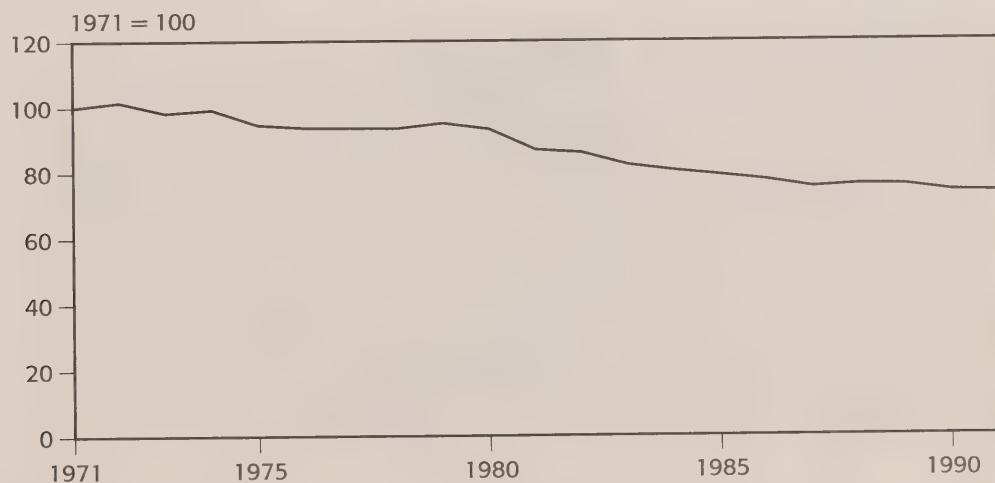
*End-use energy demand per unit of real Gross Domestic Product

petajoules by 2010, about five percent of the total estimated for that year. We have not attempted to allow for incremental DSM programs by natural gas utilities or for expansion of programs already in place.

The incorporation of new technologies in consumer appliances and industrial machinery and equipment is also likely to have an important effect. Technologies are now available, but not yet commercially viable, which make much machinery and equipment more energy efficient than existing commercial models. Many of these technologies could become viable over our study period either as a result of further technological development or as a result of policy changes designed, for example, to limit the growth in greenhouse gas emissions.[2]

In this report we have concentrated our energy demand analysis on assessing the implications of variations in two important factors affecting energy demand, natural gas prices and the structure of the economy, rather than addressing the full range of uncertainty with respect to future energy demand. We believe that the full range of possible future outcomes is better reflected in the wider range of uncertainties analyzed for the 1991 report, much of which we think remains valid (Figure 4-3). In that report we argued that it was plausible that total end use energy demand in Canada could be as low as 8 500 petajoules or as high as 11 000 petajoules by 2010 (compared to the 1993 level of about 7 500 petajoules).

Total End Use Energy Demand

The three cases analyzed imply growth of end use energy demand over the next 15 years of about 1.5 to 2.0 percent per year, somewhat lower than the growth of the 1970s. However, projected growth is about double that experienced in the 1980s and is a consequence of the joint effects of a number of assumptions and factors:

- All of our price projections imply moderate rates of increase at the burner tip, so that there is not a strong additional incentive to improve the efficiency with which energy is used.

- The effect of the sharp price increases of the 1970s and early 1980s in restraining growth in energy consumption is diminishing as the replacement of the old stock of appliances and equipment with new, more energy-efficient equipment is completed.

- The structure of economic growth in our projections is such that energy-intensive goods-producing industries grow more rapidly in all cases than they did in the past decade.

The intensity of energy use continues to decline throughout our study period in all three cases examined but its rate of decline is less than half that of the late

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2   We commented extensively on the potential impact of new technology on energy demand in our 1991 Report. See, for example, pages 294-301. In our opinion much of that analysis remains valid.

FIGURE 4-3

Canadian End Use Energy Demand – Ranges of Projections
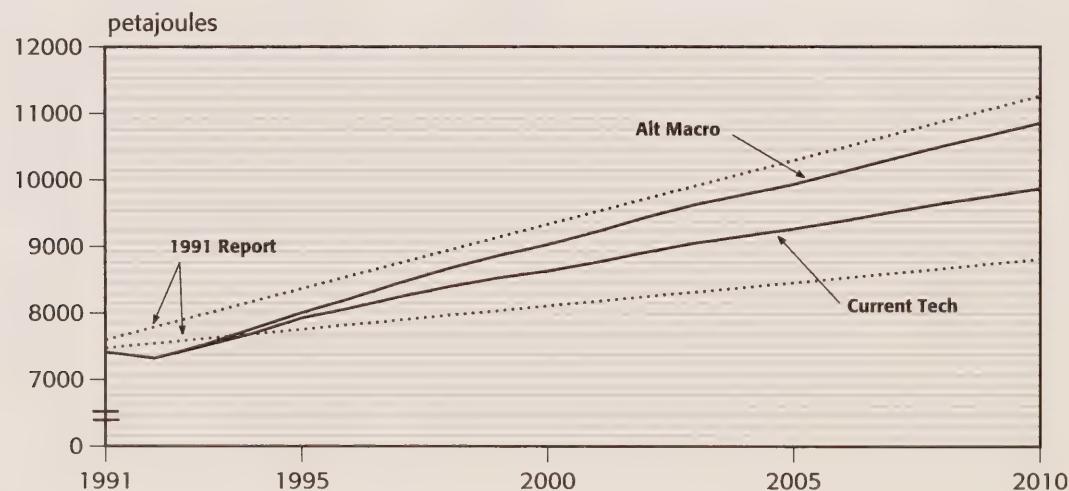
1970s and 1980s in the Current and High Tech cases. In the Alternative Macro case (in which High Tech/low gas prices prevail and economic growth is concentrated in energy-intensive industries) there is an even more modest rate of decline.

Natural gas prices and the composition of economic activity have an important impact on energy demand. Energy use by 2010 is almost 1 000 petajoules higher in the Alternative Macro case than in the Current Tech/high gas price case in which economic growth is less energy intensive. This represents some ten percent of the Current Tech level of energy use. The prices of particular energy forms have an effect, not only on total energy demand but on the shares of the different energy forms. For example, in our High Tech case, where burner tip gas prices are some 30 percent lower by 2010 than in the Current Tech case, total energy demand is some four percent higher and natural gas demand almost 30 percent higher in that year.

End Use Energy Demand by Sector

Transportation and industry together account for the largest share of energy consumption in Canada (Figure 4-4). Transportation energy use, which consists almost entirely of petroleum products, dominates end use oil demand. Industrial energy use is strongly affected by the level and structure of economic activity.

The projected growth in total end use energy demand is a result of different trends in the energy-using sectors – residential, commercial, industrial and transportation.

The analysis of all three cases implies growth in total **residential energy use** (Figure 4-5) at a rate very similar over our projection period to that which occurred in the past two decades, namely somewhat less than one percent per year. This results from the offsetting effects of a number of developments:

- In our analysis the number of households and income per household grow at considerably slower rates over the study period than they have in the past (tending to moderate growth in energy use).

- Average residential energy prices grow at a much more modest rate than in the recent past (tending to accelerate growth in energy use).

The net result of these forces is unchanged growth in household energy use.

The overwhelming proportion of residential energy use, about 80 percent, is for space and water heating in which electricity, gas, light fuel oil and, in some regions, wood are usable and substitutable. The remainder of energy use is largely electricity-specific in that it consists of energy for lighting and appliances.

Use of natural gas and electricity for space heating rises over our study period at the expense of oil. Electricity use for space heating is concentrated in the Atlantic provinces where gas is not available at present, and Québec where there is a strong preference for

FIGURE 4-4
Sectoral Shares of End Use Energy Demand – 1991
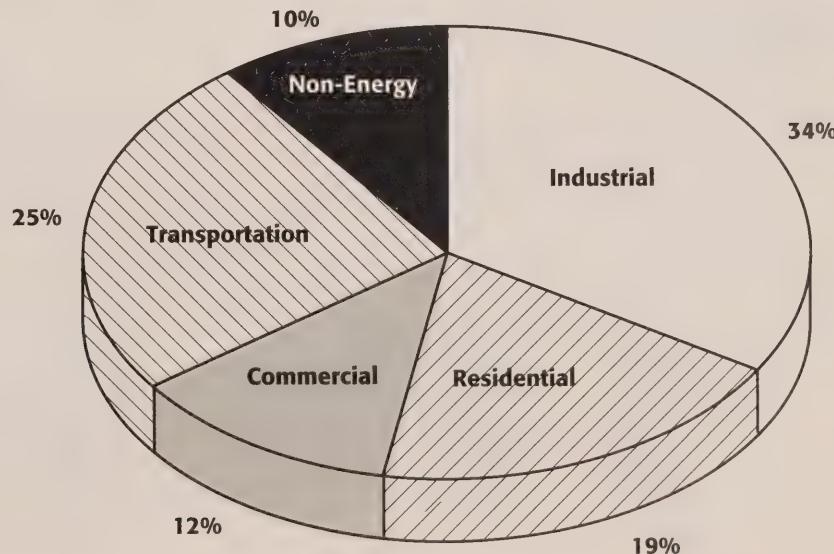
electricity. The electricity share of household energy use also reflects the rising energy demand associated with an increasing number and variety of electrical appliances.

Our analysis suggests that the impact of the lower, High Tech, natural gas prices on total household energy demand is small. This is not surprising. Gas is already the fuel of choice for residential space and water heating in all provinces west of Québec. In Québec, even with the substantially lower High Tech gas prices, natural gas use changes little. Total household energy demand is marginally higher as a result of the lower gas prices in the High Tech case – lower gas prices reduce consumers' gas bills leaving larger amounts of income available to purchase other goods and services, some of which use energy. The Alternative Macro case reduces household energy demand, but very slightly, relative to the High Tech case because personal income growth is marginally lower in that situation.

Energy use per household continues to decline in the projection period but at a much slower rate than in the recent past. This is the net result of a number of factors which influence household energy demand:

- The thermal efficiency of the housing stock is improving.

- Higher efficiency equipment for space and water heating replaces old equipment.

- Increasing ownership and use of electronic equipment by households tends to increase intensity.

- Our demographic projection features a decline in the average number of persons per household which reduces energy use per household.

The **commercial sector** (Figure 4-6), which includes all of the service-producing industries and institutions such as banks, retail stores, government administration and hospitals, uses energy in ways similar to households. As the Canadian economy became more service-oriented during the past several decades, the commercial sector grew rapidly. Like other organizations commercial enterprises sought ways to reduce energy expenditures as energy prices rose in the 1970s and early 1980s. Combined with more stringent building standards, the price increases led to construction of more energy efficient office space and improved efficiency of space heating and lighting. On the other hand, technological developments and measures to enhance productivity in the work place resulted in greater use of electricity-using equipment such as personal computers, laser printers and fax machines contributing to an average annual growth in commercial electricity demand of close to 4.0 percent per year between 1980 and 1991. Nonetheless the impact of the rapid increase in average energy prices during those years, combined with government programs inducing energy conservation, resulted in an appreciable decline in energy intensity: commercial energy demand rose at only about half the rate at which its output increased in the period 1973 to 1991.

FIGURE 4-5
Residential Energy Demand by Fuel
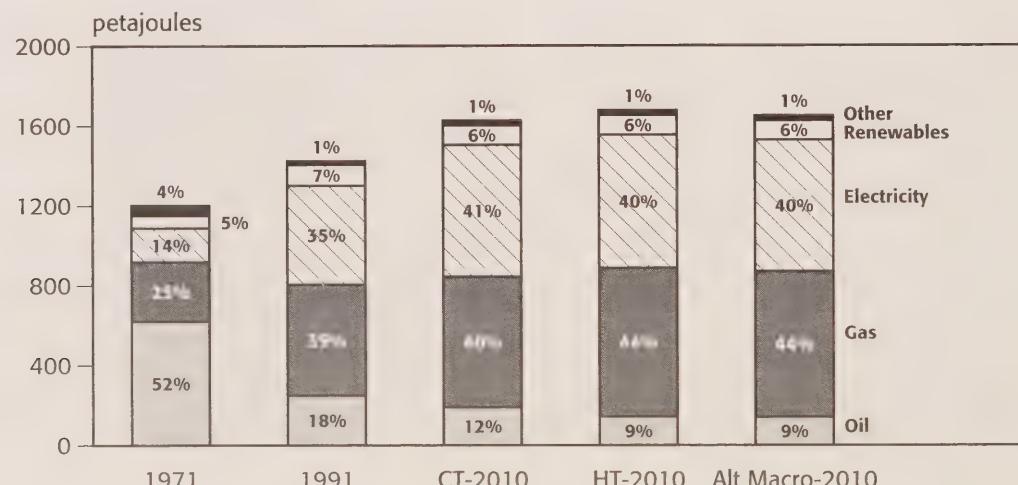
Our analysis has energy use in the commercial sector continuing to grow at a rate similar to that of the recent past – between 1.2 and 1.4 percent per year. Although our economic projection has commercial sector activity increasing at a considerably slower rate than in the past, the rate of energy price increase is also much lower than that experienced over the past fifteen years. This results in a smaller economic incentive to use more energy-efficient equipment and, consequently, the rate of decline in energy intensity in the commercial sector is projected to be considerably lower than in the past.

In all three cases analyzed, electricity's share of commercial energy demand increases at the expense of natural gas and light fuel oil. This reflects the relatively large proportion of commercial sector energy use that is electricity-specific but also the assumption that offices will become even more "electronic" over our study period.

In the High Tech case, in which commercial natural gas prices are about 30 percent lower in 2010 than under Current Tech assumptions, natural gas captures a modestly greater share of the space heating market at the expense of light fuel oil.

In the Alternative Macro case, growth in commercial economic activity is slower and this modestly reduces commercial energy demand. The difference between the highest and lowest cases is small, however, amounting to some 40 petajoules (3.5 percent) in 2010.

The **industrial sector** (Figure 4-7), which includes goods-producing industries in the economy, is very energy-intensive. It accounts for about one-third of total end use energy demand, the largest share of any sector.

Both of our economic projections have industrial economic activity growing more rapidly over our study period than it has during the past two decades and, in all cases analyzed, industrial sector energy demand growth is at least double what it was over the past 20 years. The increase in end use industrial demand occurs notwithstanding a decline in energy intensity. This decline reflects, in part, the adoption of more energy-efficient industrial processes in many industries over our study period and the impact of the recycling of some commodities such as aluminum, steel and newsprint.

Industrial energy demand is lowest in the Current Tech case and highest in the Alternative Macro case. This is to be expected since the Alternative Macro case combines faster growth in energy-intensive production with lower gas prices.

In the High Tech case lower gas prices by themselves have a modest impact on total industrial energy demand but they have a strong impact on its composition by fuel type. In the Current Tech case, in which natural gas prices rise rapidly relative to those of competing energy forms, we project a substantial reduction in the share of industrial natural gas use.

In this case heavy fuel oil is substituted for natural gas. The extent to which HFO can be substituted for gas has been a controversial aspect of our analysis in the past. In the course of our consultations many observers and analysts argued that, because heavy fuel oil use declined dramatically between the early 1970s and the present, neither the transportation infrastructure nor the industrial facilities to burn it have been preserved at previous

FIGURE 4-6
Commercial Energy Demand by Fuel
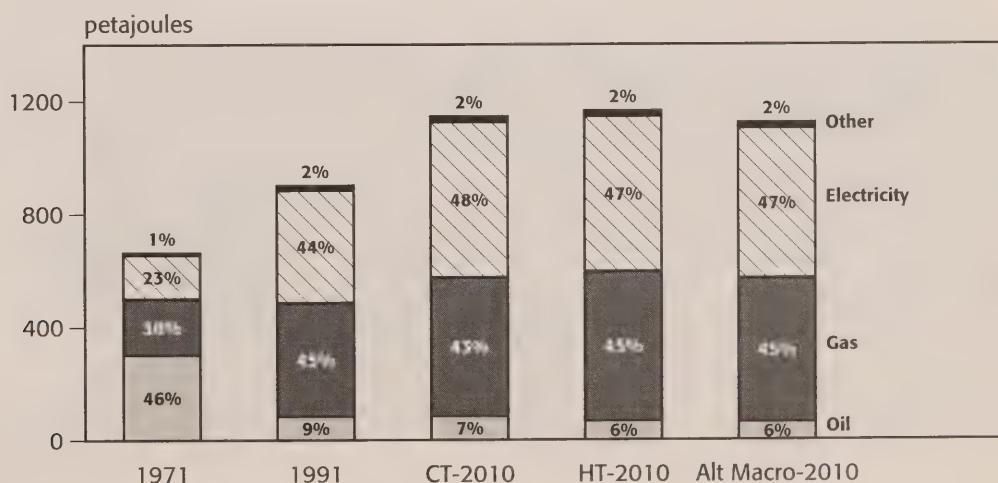
levels. As a consequence they argued that there is very limited scope for switching by industrial consumers from natural gas back to heavy fuel oil in response to relative price changes.

In our view, unless there are legislated barriers to the use of an energy form, its use can be expected to respond to changes in relative prices over a period as long as our study period. We recognize, however, that the costs of switching may be higher now, perhaps appreciably so, than they were in the past. As noted we allowed for this by raising the price of heavy fuel oil used in our analysis by a substantial amount relative to the crude oil price.

Our analysis suggests that, should natural gas prices rise relatively rapidly, as in the Current Tech case, it is at least plausible that the use of heavy fuel oil in the industrial sector could rebound to levels of the early 1970s. Should natural gas prices rise more modestly relative to oil prices, as in the High Tech case, the HFO share would remain near its present level, implying a small increase in HFO use over our projection period.

Another noteworthy feature of the industrial sector fuel distribution over the study period is that, in all three cases, the electricity share rises reflecting the increasing use of electrical processes in, for example, the pulp and paper, smelting and refining, and iron and steel industries.

Transportation energy use is dominated by use in road vehicles which at present accounts for some 80 percent of the total transportation energy used in Canada. The remainder consists of energy used by air, rail and marine industries.

Transportation energy use consists almost entirely of refined petroleum products. Limited amounts of natural gas and propane are used in road vehicles. We have allowed for a very modest increase, from 32 petajoules in 1991 to 57 petajoules in 2010, in the use of natural gas and propane in vehicles over our projection period. These fuels tend to be most economical and convenient when used in commercial vehicle fleets. Their use in private vehicles is limited at present by the lack of an extensive fuel distribution network.

Automobile energy demand, which consists almost entirely of motor gasoline, is projected to grow at a rate of about 1.6 percent per year over our study period, an increase from the rate of the past 18 years. This is the net result of our assumptions about the key determining variables; the size of the car fleet, its average efficiency, and the average annual distance driven per vehicle. We have projected growth in the automobile stock of close to two percent per year over our study period, reflecting more slowly growing personal disposable income over our study period than in the past as well as more moderate growth in the number of households.

New car fuel efficiencies improved dramatically in the 1970s and early 1980s as the price of gasoline rose sharply and Corporate Average Fuel Economy (CAFE) standards were imposed in the U.S. by the federal government to regulate the fuel efficiency of new cars. Since 1983, however, the fuel efficiency of new cars has stabilized at about 10 litres per 100 kilometres as consumers' tastes shifted back towards larger vehicles in an era of declining real gasoline prices. We have

FIGURE 4-7
Industrial Energy Demand by Fuel
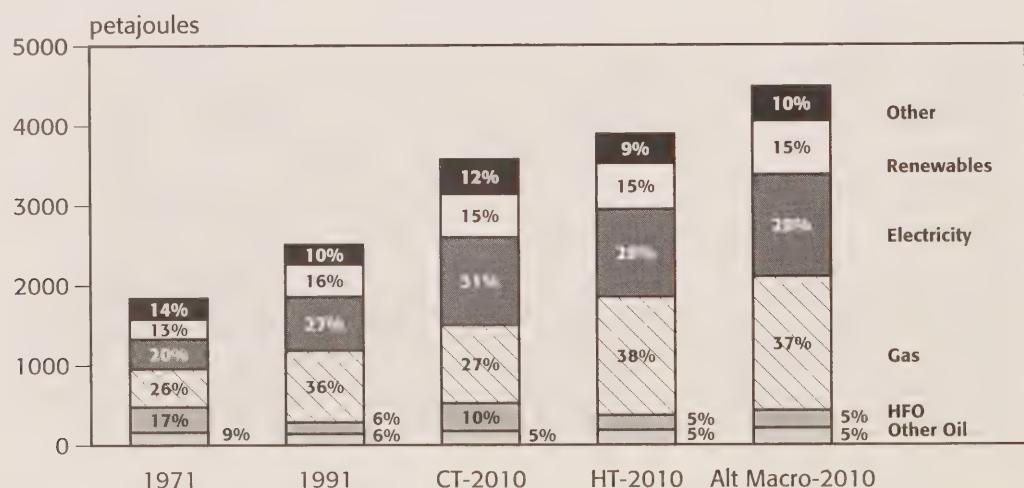
maintained the average new car fuel efficiency at this level throughout our projection period. This assumption is consistent with only modestly increasing world oil prices and assumes that CAFE standards remain at present levels.

Truck energy demand is more difficult to analyze. The share of light trucks in the truck fleet has been increasing. Light trucks are, to a considerable but unknown extent, used as passenger vehicles by households rather than as commercial vehicles. This is important because commercial enterprises use vehicles much more intensively than do households.

Our projection assumes that, reflecting recent trends, medium-sized trucks will increasingly use diesel fuel and that the medium and heavy truck fleet will increasingly consist of extra heavy trucks. Both of these developments reflect a desire on the part of operators both to economize on energy costs and to maximize payload efficiency. Truck energy demand is projected to grow at about 1.5 percent per year over our study period, a rate about three-quarters that of the past 18 years.

Truck energy consumption growth is modestly higher in the Alternative Macro case. The assumed shift of economic activity away from services and towards energy-intensive goods production in that case implies a greater demand for transportation services.

Energy use in air transport is projected to grow at 2.7 percent per year, a rate somewhat higher than the past 18 years (1.5 percent per year), reflecting higher growth in air passenger kilometres and little change in average aircraft fuel efficiency. The existing fleet is large enough to handle most projected growth.

Energy use by the rail and marine industries is projected to grow about 1.5 percent per year over our study period, higher than has recently occurred. This reflects our projection of strong growth in the industrial economy and some slowing of the rates of fuel efficiency improvement.

In total, transportation energy demand in Canada (Figure 4-8) is projected to rise, under our assumptions, at about 1.7 percent per year over our study period compared to 0.9 percent per year in the period since 1973. Our analysis suggests that transportation will continue to be fuelled to an overwhelming extent by refined petroleum products. Further, the continued increasing dieselization of the truck fleet implies that the use of diesel fuel will continue to rise relative to the use of motor gasoline.

Energy commodities are also used for **non-energy uses** such as feedstocks for petro-chemical production, the production of asphalt and lubricating materials. Petro-chemical feedstock use accounts for about two-thirds of the non-energy use of hydrocarbons.

We have allowed for an expansion of non-energy use of hydrocarbons of about 375 petajoules per year by 2010 from its current level of 650 petajoules. Most of the increase is accounted for by an increase in the demand for natural gas and natural gas liquids as petro-chemical feedstocks. The increase is higher in the High Tech case, about 415 petajoules, since natural gas feedstock is cheaper.

End Use Energy Demand by Fuel and Region

In general regional growth in end use energy demand reflects regional demographic changes and the regional distribution of economic growth which underlies the economic projection outlined in Chapter 2.

FIGURE 4-8
Transportation Energy Demand By Fuel
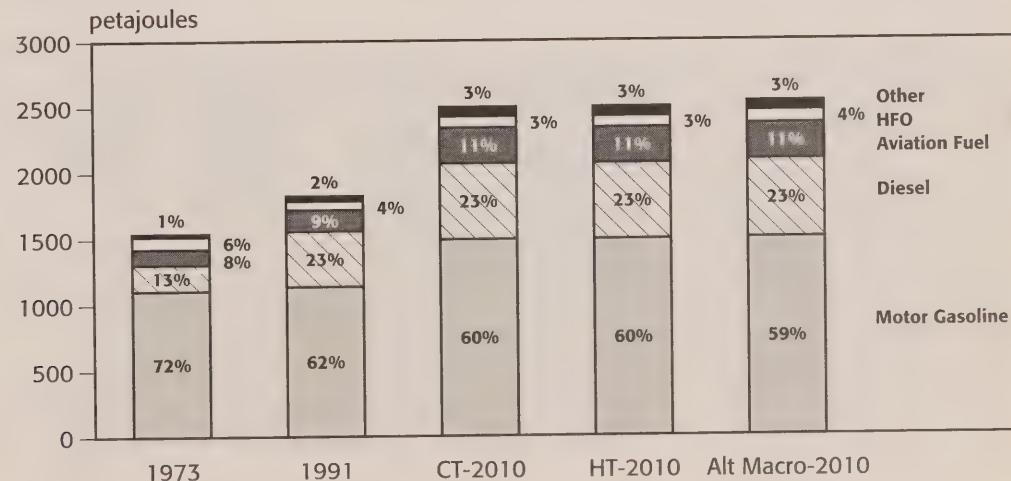
The High Tech/low gas price case (Figure 4-9) generates higher growth in end use energy demand than the Current Tech/high gas price case in all provinces west of Québec. There is no difference in the Atlantic region because, although gas may be available from Sable Island toward the end of the projection period in the Current Tech case, we have not accounted for it in our demand projections. There is a minimal effect on total energy demand in Québec because of the small share of natural gas in that province's fuel use mix.

The Alternative Macro case, however, generates higher energy demand growth in all regions with the largest increases occurring in Québec, Ontario and B.C. This regional impact reflects the geographic distribution of energy-intensive, goods-producing industries whose output, and therefore energy demand, is higher in the Alternative Macro case. For example, pulp and paper are important in Québec and B.C. and iron and steel in Ontario.

Regional fuel use varies because of the availability of natural gas and renewable energy forms, different relative energy prices and different consumer preferences across provinces (Figure 4-10).

In the **Atlantic region** our projections (Figure 4–11) have total end use energy growing from 514 petajoules in 1992 to between 625 and 660 petajoules in 2010 depending on the economic growth assumptions.

FIGURE 4-9
Regional End Use Energy Demand – 2010
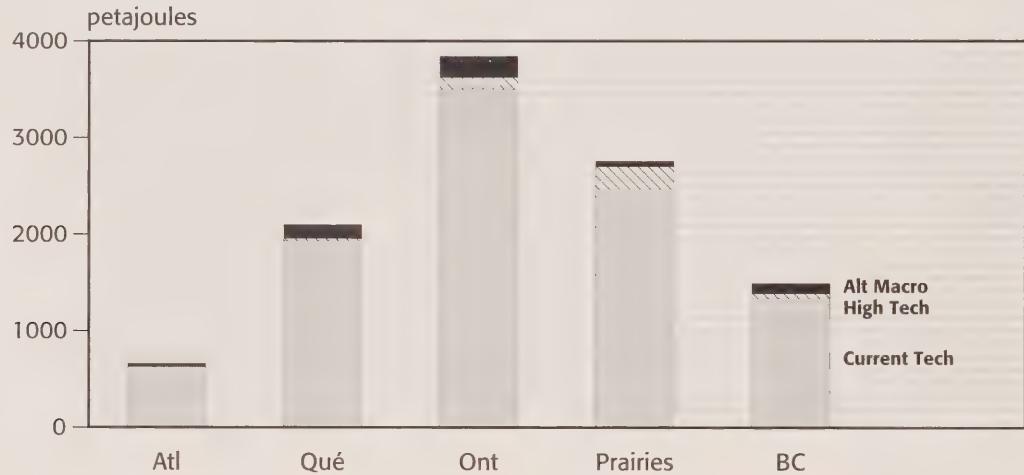
FIGURE 4-10
End Use Fuel Shares by Region – 1991
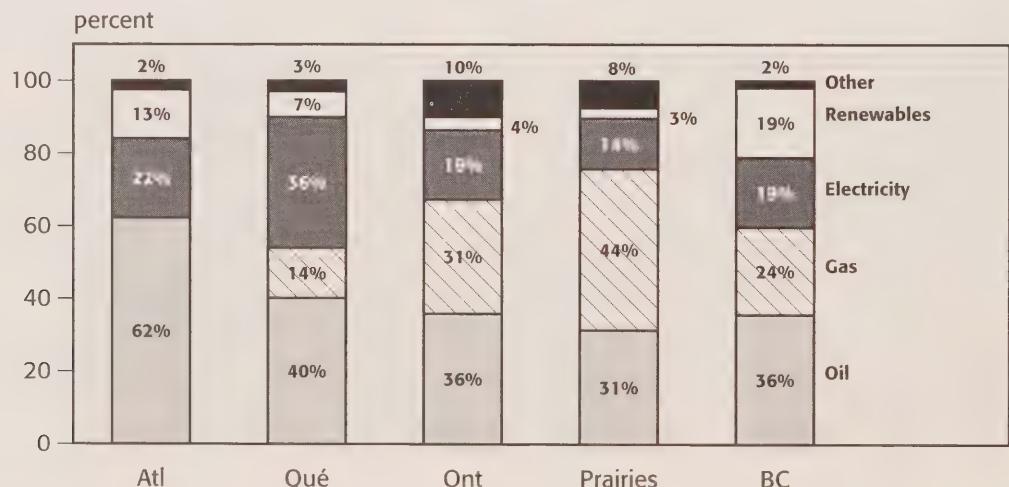
The major development in fuel use has been a dramatic shift away from oil used for non-transportation purposes towards electricity and renewable energy, largely in the form of wood and wood wastes. Our analysis suggests a moderate continuation of the tendency to substitute electricity for non-transportation oil use. This is primarily due to a shift towards electricity in residential and commercial space-heating uses reflecting the assumed relative decline in electricity prices. Although the use of renewable energy continues to increase moderately, its share of total energy use declines slightly in all cases. This largely reflects physical constraints on further increases in the use of wood among households. Wood is already extensively used in rural areas of the Atlantic region and is unlikely to penetrate urban areas because of the high cost of transportation and the inconvenience of storage and use.

In our analysis, the pattern of fuel use in **Québec** (Figure 4-12) is sensitive to the path of natural gas prices. In all three cases there is a shift towards increasing use of electricity. In the Current Tech case the shift is entirely at the expense of natural gas as gas prices in that case rise relative to those of electricity and oil products, particularly heavy fuel oil. In the Current Tech case, natural gas use in Québec actually falls from current

FIGURE 4-11
End Use Energy Demand by Fuel – Atlantic
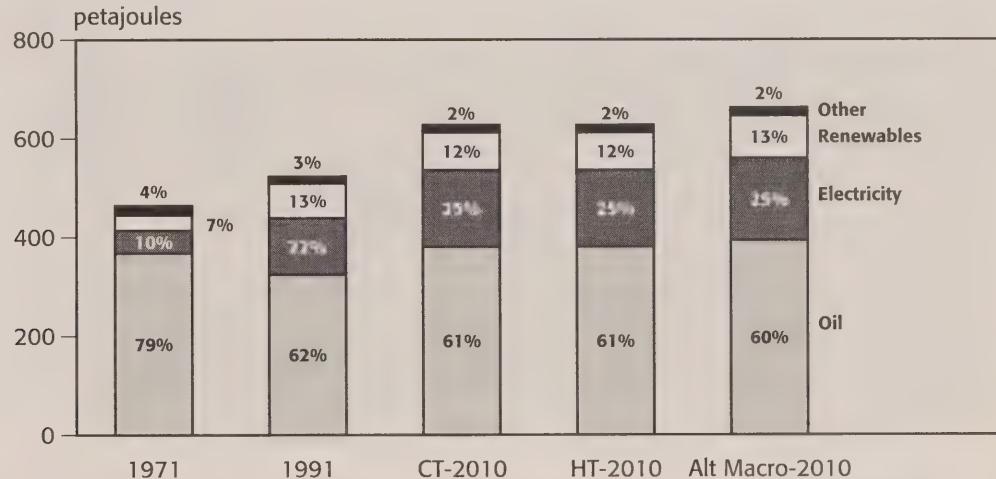
FIGURE 4-12
End Use Energy Demand by Fuel – Québec
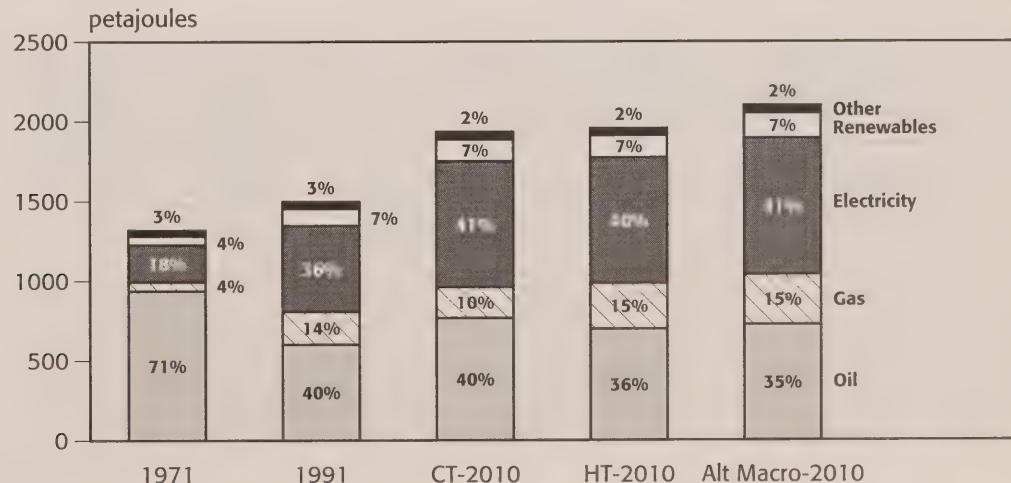
levels by the end of our study period, because gas prices in Québec are the highest in the country. In the High Tech and Alternative Macro cases, natural gas prices increase at a much lower rate. In these cases natural gas preserves its market share; it increases from 1 520 petajoules in 1992 to between 1 935 and 2 100 petajoules in 2010, at the expense of oil used for non-transportation purposes, largely heavy fuel oil in industrial use.

In **Ontario**, fuel shares change little (Figure 4-13) over our study period except in the Current Tech case in which the sharp increase in the price of natural gas relative to electricity and oil products causes gas use to decline in relative terms and the shares of other fuels to increase modestly. Should natural gas prices increase at the more moderate rate of the High Tech case, which is also a feature of the Alternative Macro case, there is very little change in the distribution of fuel use over our study period.

In the **Prairie provinces** total end use energy is projected to increase from 1 777 petajoules in 1992 to between 2 470 and 2 750 petajoules in 2010 (Figure 4-14). Much of the projected increase and most of the difference between the two cases in 2010 result from developments in Alberta. In that province natural gas use

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FIGURE 4-13
End Use Energy Demand by Fuel – Ontario
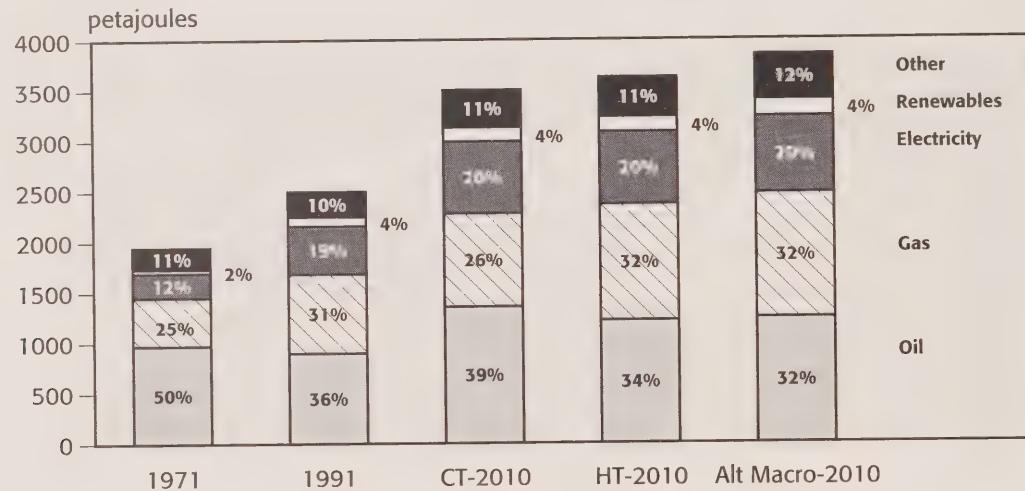
FIGURE 4-14
End Use Energy Demand by Fuel – Prairies
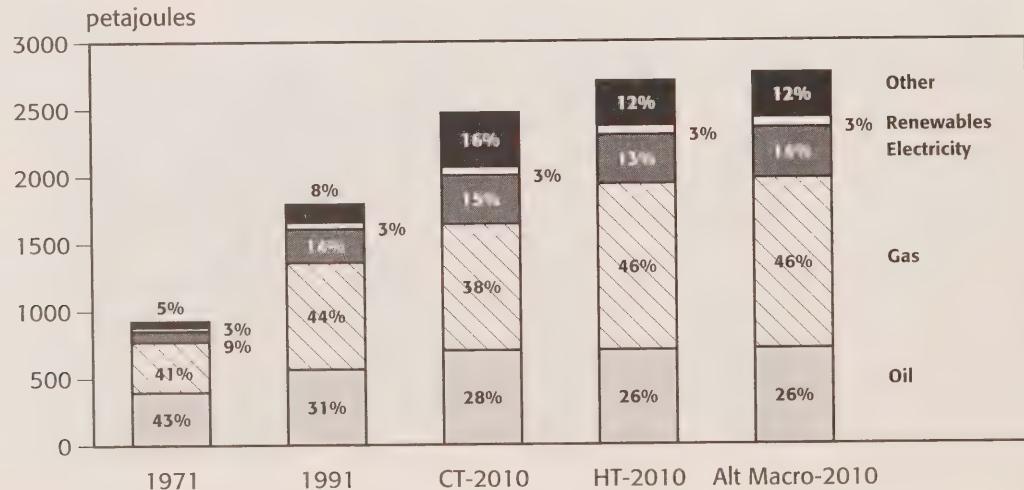
is dramatically higher in the High Tech and Alternative Macro cases as petro-chemical production is higher and use of natural gas in bitumen production expands substantially. The price sensitivity of natural gas use in bitumen production also generates the different fuel distribution in 2010 in the Current Tech as compared to the other cases.

In Manitoba and Saskatchewan, growth in end use demand is modest in all cases and the shifts in the distribution of fuel use across the three cases are not large. This reflects the limited substitutability between natural gas and other fuels, particularly in industrial processes.

In **British Columbia** the pattern of energy use in all of our cases (Figure 4-15) evolves over our study period in the same direction as it has in the past 20 years although at a more moderate rate. Electricity and natural gas both increase in relative terms at the expense of oil in non-transportation uses. Even in the Current Tech case natural gas use continues to increase in B.C. in relative terms, reflecting low natural gas prices relative to other energy forms.

In the Current and High Tech cases, the share of renewables declines slightly in B.C. This reflects a relative slowing in the growth of the pulp and paper

FIGURE 4-15
End Use Energy Demand by Fuel – BC*

*Includes Yukon and Northwest Territories
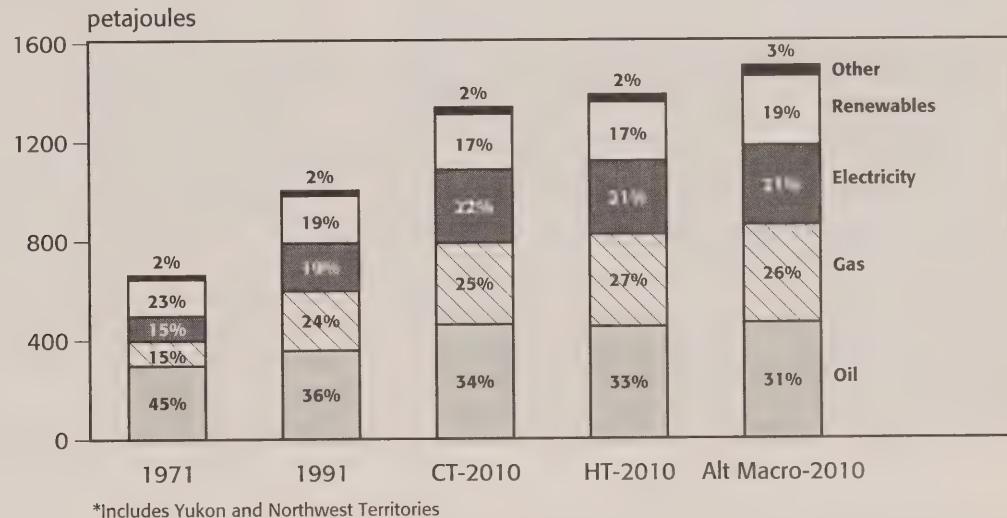
FIGURE 4-16
End Use Energy Demand by Fuel – Canada
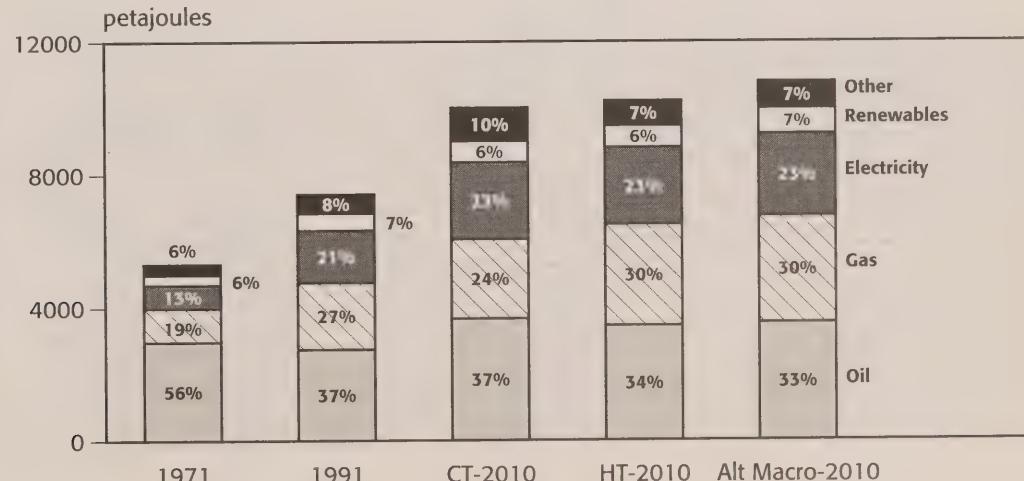
industry and some increase in the use of electricity in that industry as new processes are adopted which reduce wood waste. In the Alternative Macro case the pulp and paper industry enjoys more rapid growth and the use of renewables maintains its share over the study period.

At the national level (Figure 4-16), although the use of all energy forms increases over the study period in all three cases, the distribution is substantially affected by the path of relative energy prices. Natural gas use increases in all three cases but, in the Current Tech case where prices rise relative to those of other fuels, its rate of increase is substantially smaller than in the other cases and its share of total energy use actually shrinks.

Our analysis demonstrates some of the sensitivity of total energy use in Canada to developments in energy prices and in the structure of the economy. The combination of projected moderate increases in natural gas prices and economic growth highly concentrated in energy intensive industries produces a difference of about 10 percent or 1 000 petajoules in the level of energy use in 2010 between the lowest and the highest case. As noted these are not, in our view, the boundaries of the plausible range of energy demand over the study period. Demand could well be sustained at a level considerably below the bottom end of this range if consumer and industry preferences were to result in purchases of appliances and equipment which are more energy-efficient and if existing technology were to become commercially viable over the study period.

Total Primary Energy Use

The total amount of an energy commodity used is equal to the end use demand plus amounts used in the production and transportation of energy. For example the total amount of natural gas used in the economy is equal to the sum of the amount represented by end use, the amount of gas used in the production of oil and natural gas and, the amount used in the generation of electricity. Thus total primary energy used is about 20 percent larger than total end use energy.

Electricity does not appear in a portrayal of primary energy use (Figure 4-17) because it is a form of energy "manufactured" from basic energy sources: fossil fuels, uranium or water. Almost 80 percent of coal used in Canada is for the generation of electricity.

Little oil is used in the generation of electricity and oil used to produce and transport oil and gas is relatively small. As a consequence, the range of our projection for primary oil use is similar to the range discussed above.

The total amount of natural gas used in Canada will be influenced, perhaps strongly, by the extent to which it is used in electricity generation. Our analysis, outlined in the following chapter, suggests that, if price increases are moderate, gas used in electricity generation could increase substantially from 119 petajoules in 1992 to 535 petajoules in 2010. As a consequence the projection of natural gas use associated with the High Tech/low price case is considerably larger than High Tech end use demand. Increased gas use in electricity generation would tend to reduce the need for new coal and hydro projects.

FIGURE 4-17
Primary Energy Demand by Fuel – Canada

Chapter 5
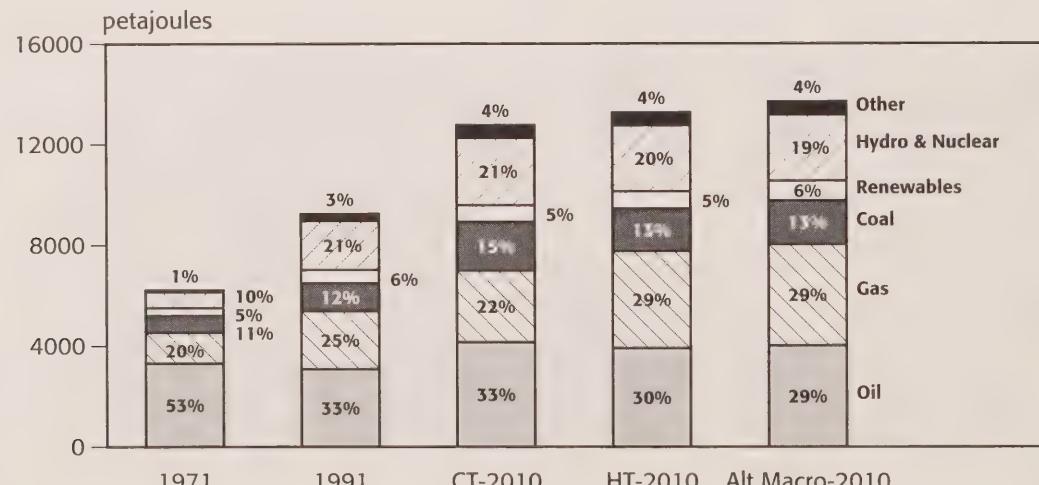
ELECTRICITY

The electricity supply industry in Canada and the U.S., as in many other countries, is undergoing substantial change:

- Load growth has been much less than earlier anticipated so that many utilities in North America have an excess of generating capacity over current demand levels.

- Uncertainty about future load growth, concerns about generation costs and the environmental consequences of electricity production have led utilities in both Canada and the U.S. to reassess their planning strategies.

- Some utilities are using a broader framework (integrated resource planning) to assess all costs, including such social costs as those associated with environmental degradation, of providing electricity services. In this context, the management of demand is considered as an alternative to the provision of additional supply.

- Further, utilities are less willing than previously to engage in construction of large-scale projects with long lead times and to enter into long-term firm power purchase contracts.

- The development of more efficient gas-fired combined cycle technology, and the emergence of independent power producers together with their potentially lower environmental impacts and small scale, have led to more use of gas in electricity generation than a decade ago, especially in the U.S.

- The 1992 U.S. Energy Policy Act gives the FERC powers to order transmission-owning utilities in the U.S. to provide transmission access to others. This is leading to increased electricity trade as the FERC encourages regional groupings of utilities and non-utility generators to implement open access on a voluntary basis.

- Canadian utilities have an interest in developments south of the border because they are inter-connected with their U.S. neighbours and engage in important amounts of cross-border trade.

- Partly as a result of developments in the U.S., there is interest in Canada in the potential for enhanced interprovincial cooperation and trade in electricity.

An implication of these factors taken together is that the range of supply options open to an individual utility is likely to be much larger in the future than it has been in the past.

At present, electricity generating systems in many provinces are characterized by large capacity surpluses. This is particularly true in Manitoba, the Maritime provinces, Ontario and Saskatchewan. The extent of the surpluses is such that, in these provinces, large base-load capacity additions are not required, given our load projections, until relatively late in the study period, or beyond. This has a major influence on the generation expansion programs that were developed in our analysis.

The focus of our analysis is on the implications for fuels used to generate electricity, and the amounts of interprovincial and international trade: we examine three different cases. The first two cases correspond to the Current and High Tech cases that are addressed throughout this report and differ with respect to gas price profiles. In the Atlantic provinces, where gas is not currently available, there is no difference between these two cases.

In both the Current and High Tech cases we assumed that generation planning would continue to be done on an individual provincial basis. In the third case, we assumed that generation planning would be conducted on a regional rather than a provincial basis where there appeared to be economic advantages in doing so. This case, the Enhanced Cooperation case[1], assumes a considerably greater degree of inter-utility cooperation than exists at present. An inherent requirement of this case is that there would be open access to transmission networks.

In all three cases, Canadian electricity demand is projected to grow at just over two percent per annum from 477 terawatt-hours in 1992 to almost 700 terawatt-hours in 2010. At present, exports of electricity to the U.S. are driven largely by the availability of surplus power in Canada, and it was assumed that this would continue. Exports remain a relatively small proportion of Canadian generation.

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1   In the Enhanced Cooperation case, we assumed the same gas price profile as that used in the Current Tech case.

To facilitate our analysis, estimates were made of the unit costs of alternative sources of incremental electricity supply in each province. We assumed that the moratorium on nuclear expansion in Ontario would remain in force, and that no new nuclear units would be installed elsewhere in Canada during the study period. The analysis indicated that, in general, hydropower is the least costly source of new major generation in B.C., Manitoba and Québec, and fossil-fuelled generation is least costly in Alberta, the Atlantic provinces, Ontario and Saskatchewan.

In the Current Tech case, the estimated unit costs of gas-fired generation are substantially higher than those of alternative hydro and coal-fired projects. In the High Tech case, with gas prices considerably lower than in the Current Tech case, the costs of gas-fired generation remain generally higher than the alternatives, but the differences are much smaller. In this situation, other factors that are important to the selection of types of generation additions, such as size of capital requirement, lead time, efficiency, and environmental and social impacts, tend to favour natural gas. Therefore, in the High Tech case, we allowed for increased installation of gas-fired combined cycle generating capacity in all provinces where gas is available.

There are potential hydro-electric projects, with relatively low unit costs, in Labrador and Manitoba that are too large in scale to be developed to serve intraprovincial markets. However, these projects, if developed to supply regional load growth, could reduce the overall cost of generation in certain regions of the country. In our Enhanced Cooperation case, some of these projects are assumed to proceed.

Electricity Production by Fuel Type

The projected levels of electricity production and changes in the distribution of fuel types in our three cases are illustrated in Figure 5-1. In all three cases, hydro generation continues to be the dominant source of electricity, although its relative share diminishes by 2010. Growth in fossil-fuelled generation is strongest in the Current and High Tech cases and lowest in the Enhanced Cooperation case. In the Current Tech case, coal-fired generation expands most, increasing its share from 16 to 20 percent. In this case, the share of gas-fired generation increases from three to five percent, mainly because of the installation of short lead time generating capacity by utilities and the expansion of independent power production, much of which is already contracted

FIGURE 5-1
Electricity Production by Fuel Type
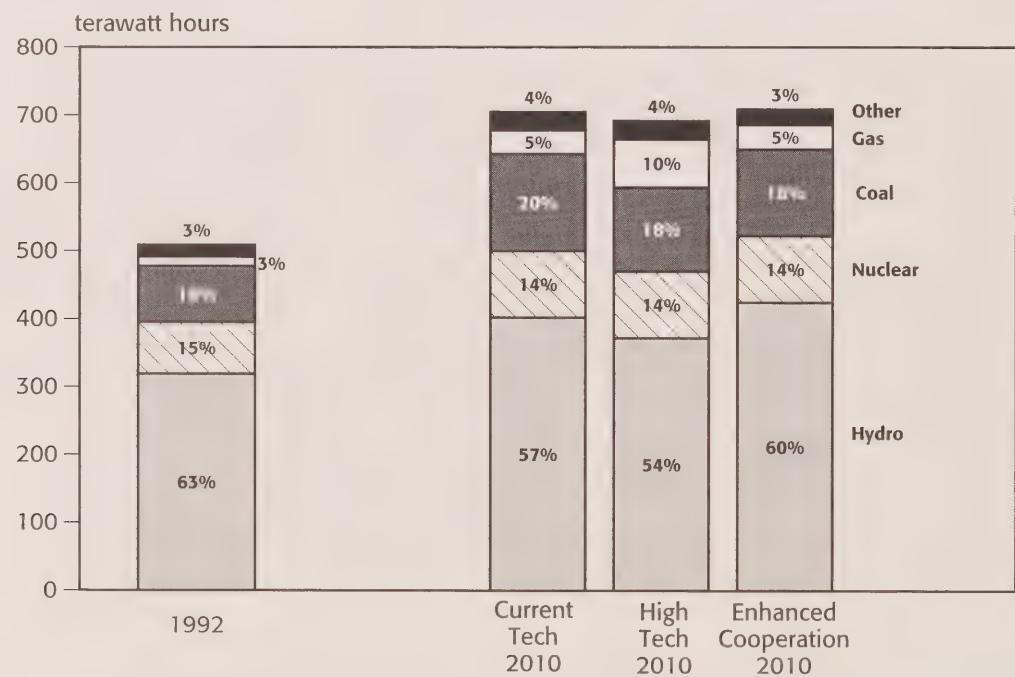
Note: "Other" includes oil, biomass, petroleum coke, orimulsion and wind.

for. Gas-fired electricity production in the High Tech case is double that in the Current Tech case by 2010 as additional gas-fired combined cycle capacity displaces some new hydro and coal-fired projects. Natural gas used in electricity generation increases from 119 petajoules in 1992 to 245 petajoules and 535 petajoules in 2010 in the Current and High Tech cases, respectively.

The greater use of hydropower generation in the Enhanced Cooperation case, relative to the other cases, is due to the development of new, large hydro-electric projects in Labrador and Manitoba to supply loads in the Atlantic provinces, Manitoba, Ontario and Saskatchewan. This results in a reduction in relatively expensive coal-fired and "other" (mainly oil-fired) generation relative to the Current Tech case. Québec continues to install relatively low-cost hydro generation to supply its own load and continues to sell surplus power to neighbouring systems.

The outcome of the Enhanced Cooperation case is that no new fossil-fuelled generating capacity is required in the second half of the next decade in any province from Newfoundland to Saskatchewan. The total saving in incremental thermal capacity is almost 3 800 megawatts. It is estimated that the unit cost of supplying incremental load using hydropower in the Enhanced Cooperation case is approximately 75 percent of the corresponding cost of using mainly fossil-fuelled alternatives in the Current Tech case.

Electricity Trade

All adjacent provincial electricity transmission networks are interconnected. Also, apart from Alberta, all provinces that border the U.S. have transmission links to neighbouring U.S. systems. These interconnections allow trade to take place, and the exploitation of trade opportunities reduces the total cost of electricity supply within trading regions. Provinces that possess abundant hydro-electric resources have a substantial cost advantage, both in the long and short run, over those provinces and neighbouring regions of the U.S. that depend mostly on fossil-fuelled generation. Further, some provinces that have nuclear and coal-fired generation can enjoy cost advantages in the production of electricity over nearby provinces and U.S. states.

The magnitude of both interprovincial and international electricity trade, today and in the future, depends on the relative mix of fuels used for electricity generation in each province. Since we assume that exports will continue to depend largely on the availability of surplus power, an inherent feature of our analysis is that electricity trade declines as existing surpluses are used up.

In 1992 the hydro-rich provinces of B.C., Manitoba, Newfoundland and Labrador, and Québec sold power to other provinces and to the U.S. (Figure 5-2). In addition, New Brunswick and Ontario sold relatively low cost surplus nuclear and coal-fired generation to neighbouring systems. Alberta sold low cost coal-fired generation to B.C., some of which was resold in the U.S. Net electricity exports to the U.S. in 1992 were in excess of 24 terawatt-hours, about five percent of total Canadian generation.

In the Current Tech case, the general pattern of trade in most regions in 2010 remains similar to that in 1992[2]. The one major change in the pattern of international trade over the study period is the assumed return to B.C. of downstream Columbia River benefits[3]. This results in B.C. becoming a net importer of electricity by the end of the century. Canadian net exports of electricity to the U.S. in 2010 in the Current Tech case are estimated to be somewhat less than 16 terawatt-hours, about 35 percent lower than in 1992. This is equivalent to just over two percent of total generation in Canada by the end of the study period.

In the High Tech case, which is not illustrated in Figure 5-2, the pattern of trade in 2010 is similar to that in the Current Tech case. Interprovincial and international transfers from B.C., Manitoba and Québec are slightly less by the end of the study period compared with the Current Tech case because of the substitution of gas-fired combined cycle capacity for some new hydro projects in these provinces in the latter part of the study period. The only other significant change is that transfers from Alberta to B.C. are much reduced compared with the Current Tech case. This occurs because, in the High Tech case, gas-fired combined cycle units, which have a relatively high fuel cost, are substituted for some of the new, low fuel cost coal-fired units that are included in the Current Tech case.

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2   Since 1992 was not an average hydro production year, the comparison between 1992 and 2010 of sales from the hydro-rich provinces is somewhat misleading; over the projection period average hydro production conditions were assumed. For example, the apparent increase in transfers from Labrador to Québec between 1992 and 2010 is due to the fact that 1992 was a below-average production year at the Churchill Falls hydro-electric development.

3   The Columbia River Treaty provides that the power generated at hydro-electric plants on the U.S. portion of the Columbia River which is attributable to streamflow regulation from storage reservoirs in B.C., and which were sold to the U.S., will be returned to the Province of British Columbia starting in 1998. B.C. will have to choose between recovering the power for domestic use or reselling it in the U.S.

FIGURE 5-2
Net Electricity Trade
(Gigawatt hours)

1992

BC ← 1704 ← ALTA ← 106 ← SASK ← 362 ← MAN — 1735 → ONT ← 479 ← QUÉ ← 25985 — LAB
511
7473   72   6058   1659   7455   1674   NB — 738 → PEI
194
NS

2010 - Current Tech

BC ← 2313 ← ALTA — 39 → SASK ← 157 ← MAN — 551 → ONT ← 381 ← QUÉ ← 31788 — LAB
1090
386   65   1622   3254   9626   1437   NB — 1130 → PEI
351
NS

2010 - Enhanced Cooperation

BC ← 2313 ← ALTA — 0 — SASK ← 2557 ← MAN — 5838 → ONT ← 9144 ← QUÉ ← 43787 — LAB   4195 — NFLD
4349
3422   52   1622   3786   9626   1209   NB — 1130 → PEI
1366
NS
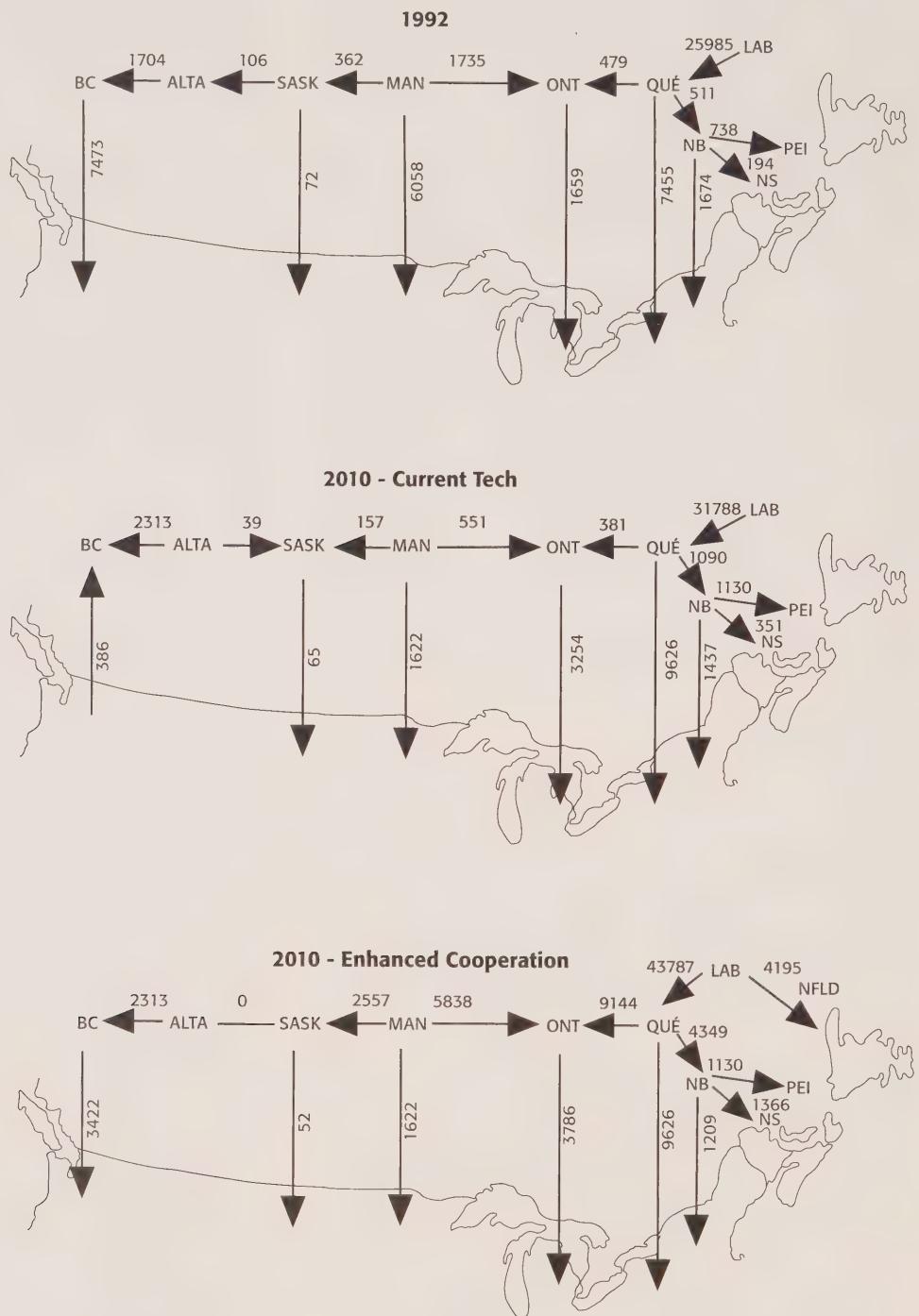
Note: Net trade shown here excludes non-revenue exchanges.

The pattern of interprovincial and international electricity flows in 2010 is substantially changed in the Enhanced Cooperation case. Most of the generation from the new hydro-electric projects on the Lower Churchill River in Labrador is transferred through Québec to the Maritimes and Ontario, and a portion is transmitted through a new submarine cable to the island of Newfoundland. Most of the additional hydro-electric production in Manitoba flows to Ontario and Saskatchewan to displace projected fossil-fuelled generation in those provinces. In the Enhanced Cooperation case, it was assumed that B.C. would resell its entitlement of power from downstream Columbia River hydro projects in the U.S markets since there may be economic benefits in doing so. As a result, B.C. remains a net exporter of electricity. Total Canadian exports to the U.S. in this case are almost 20 terawatt-hours, or just less than three percent of total Canadian generation. Interprovincial flows in 2010 in this case are approximately 75 percent more than in the Current Tech case.

NATURAL GAS

For most of the past decade the natural gas industry in North America has been in a state of transition.

During the late 1970s and early 1980s natural gas prices in the U.S. and Canada had been regulated at sufficiently high levels that the use of gas was discouraged but producers had a strong incentive to explore for new reserves. In Canada, the Board's use of quantitative surplus tests in its regulation of gas exports tended to restrict access to U.S. markets by Canadian producers. By the mid-1980s, productive capacity greatly exceeded the demand for natural gas and large volumes of gas were shut in.

In 1986 administered prices for natural gas were eliminated in Canada; a gradual phase-out began in the U.S. in 1978, resulting in complete deregulation of wellhead prices in 1993. Price deregulation was accompanied by the opening up of access to pipelines and revisions to the Board's export surplus determination procedures in 1987. Natural gas is now traded in an increasingly integrated and competitive North American marketplace.

Because price deregulation occurred at a time when there was a large surplus of productive capacity, natural gas prices subsequently declined precipitously in North America, falling by about one-half between 1986 and 1992. The decline in prices induced an appreciable increase in the demand for natural gas, especially in the U.S. Producers met the increasing demand by drawing on existing productive capacity; the very low prices combined with large excess productive capacity effectively eliminated any incentive for producers to search for and develop new gas reserves. These phenomena produced a gradual decline in excess productive capacity so that, at present, natural gas markets in North America are roughly in balance (Figure 6-1). The decline in excess productive capacity was mirrored in a steady decline in the ratio of remaining reserves to production in Canada and the U.S. as the distortions induced by price and export regulation were worked off. Over the past two winters there have been increasing signs of price firmness; indeed, on an annual average basis, natural gas fieldgate prices in Alberta increased in 1993 by 27 cents to $1.58 per gigajoule[1], the first increase in 10 years (Figure 6-2).

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1   One gigajoule is approximately equal to .95 million Btu or .95 thousand cubic feet.

FIGURE 6-1

Canadian Gas Annual Productive Capacity and Production
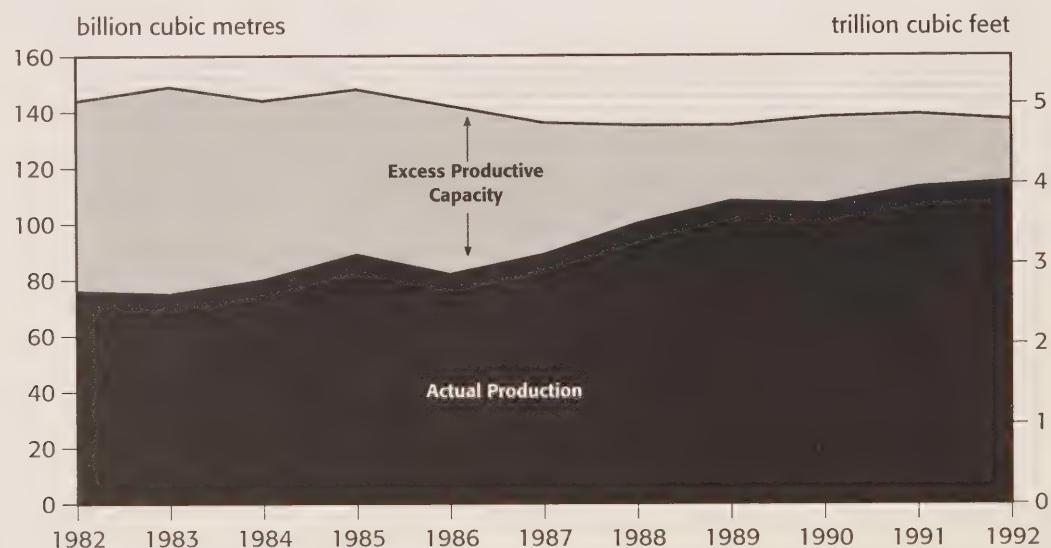
Analytical Framework

The Board bases its analysis of natural gas supply on the premise that natural resource commodities are exhaustible and that replacement and production costs increase as the resource is exploited. Though many, if not most, analysts accept this assumption in a very long run context, it is increasingly questioned whether it is an appropriate assumption for analysis over shorter periods such as 10 to 20 years. Moreover the history of mineral commodity prices reveals that supply costs and hence prices of some commodities tend to remain flat over their period of exploitation. This suggests that the path of supply costs may not behave in accordance with the exhaustible resource view.

Estimates of the size of the natural gas resource base have steadily increased over time as cumulative production and remaining gas reserves have increased (Figure 6-3). Indeed, discovered reserves in 1992 were greater than estimates of the ultimate potential of the basin in the early 1970s. It is noteworthy that these estimates relate to "conventional" gas resources only, i.e., those in geological formations which can be exploited with currently available technology. So called unconventional resources such as gas present in coal seams and in formations of low permeability are known to be large. Because they cannot be profitably produced with current technology they have not been included in previous analysis by the Board.

FIGURE 6-2
Alberta Fieldgate Gas Prices

* Average annual prices 1985 to 1987, monthly prices 1988 to 1993 (nominal dollars).
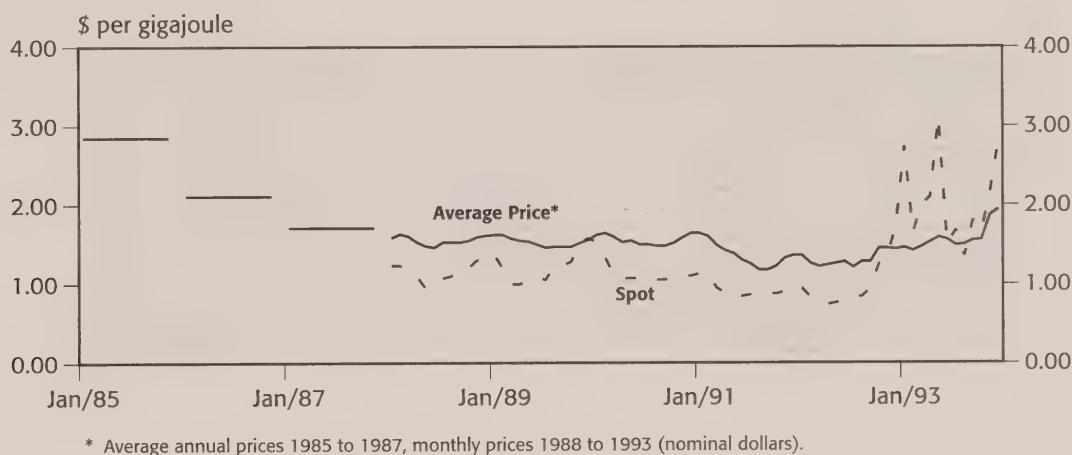
FIGURE 6-3
Gas Resource Potential – Western Canada Sedimentary Basin
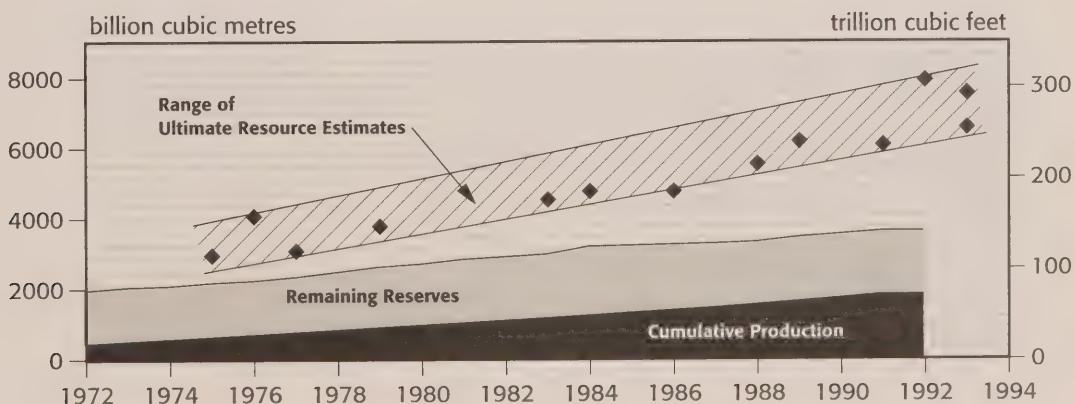
Perceptions of the size of the resource base are linked to current opinion on possible trends in the cost of incremental gas supply. Though analysts have generally assumed that finding and production costs of gas will increase in the future, there is limited and ambivalent evidence of such a trend in the historical record; the presumed date for the commencement of increasing costs of resource exploitation continues to be pushed into the future. In fact, exploration and production costs for natural gas have declined in recent years. The energy "shocks" of the seventies make recent data hard to interpret, but finding and production costs for Alberta in 1991 appear to have been lower than in 1981; they declined from an estimated $1.00 per gigajoule in 1981 to $.65 per gigajoule in 1992. B.C. has experienced a substantial decline since 1984.

An alternative view of the prospects for the supply of gas infers from such evidence that a combination of improved geological understanding and steady advances in exploration and production technology continually operate to allow incremental reserves to be found and produced at a relatively constant cost. There is a large and growing body of literature documenting advances in hydrocarbon finding and production technology and analysts are increasingly allowing for future technological progress in their projections.[2] There are numerous examples of recent technological advances in exploration (e.g., three-dimensional seismic analysis), drilling (the use of measurement while drilling, the availability of more durable bits and better drilling mud) and production (use of hydraulic fracturing techniques, and of continuous production tubing).

Thus, a key element of our analysis focuses on exploring the implications for North American gas markets of two alternative views of gas supply prospects:

- The conventional resource will continue to comprise the bulk of production over our study period, and it will be increasingly expensive to exploit (the Current Tech view).

- New advances in technology and geological knowledge will prevent the cost of finding and developing new gas reserves from rising appreciably. Additionally, improved technology could result in unconventional resources being developed at costs similar to those of conventional gas (the High Tech view)[3].

These alternative views are reflected in the relationships between the costs of supplying new gas reserves and cumulative reserve additions (supply cost curves) shown in Figure 6-4. In the Current Tech case the 1994 supply cost curves are based on our evaluation of undiscovered conventional resources and their associated costs of exploitation. The corresponding relationship from the Board's 1991 report is also shown. The rightward shift in the Board's estimated relationship over time is evident and reflects a higher estimate of conventional resource potential (in the Current Tech case) shown in Figure 6-3. The Current Tech relationship shows costs rising more slowly than in previous Board analysis; the High Tech relationship implies that production costs barely increase above present levels. Our High Tech analysis assumes that flatter cost/reserves relationships apply to all basins in North America.

There are other important uncertainties, related to both demand and supply, about the prospects for North American gas markets, some of which we have analyzed in this report.

The use of natural gas for electricity generation has expanded in North America, partly as a result of recent low prices but also because of its relatively favourable environmental qualities and the need by electricity producers for generating units which are small scale, have short lead times for construction and are efficient. Consequently future gas demand in the U.S. could be considerably higher than many are estimating. This would be more likely if gas use were encouraged in the future by the development and implementation of government policies related to greenhouse gas emissions. Although our analysis does not incorporate any such policies, we have examined the impact on North American gas markets of a U.S. gas demand profile, which is higher by as much as three exajoules than that assumed in the Current and High Tech cases

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2   The Gas Research Institute and the National Petroleum Council are two examples in the U.S. In Canada, Armstrong and Calantone have expressed this view in recent years on behalf of ANG. Refer to:

Gas Research Institute, *1993 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Chicago, Illinois, June 1993.

National Petroleum Council, *The Potential for Gas in the United States*, Washington, D.C., December 1992.

Alberta Natural Gas Company Limited, *1993 Facilities Expansion* (NEB Hearing Order GHW-2-91), May 1990.

Alberta Natural Gas Company Limited, *Supply, Cost, Technological Change, and "Export Performance Analysis"* (Export Impact Assessment, NEB File 7500-A000-2), December 1992.

3   The supply cost projection we use implies a rate of technological progress of about two percent per year.

(the "higher U.S. demand" case).[4] This analysis provides a background for the Export Impact Assessment component of the Board's Market-Based Procedure.

In addition to uncertainties about natural gas use there is a possibility of additional supply from new sources of conventional gas in the North American gas market. For example, Mexico is known to have large undiscovered and unexploited gas resources with an ultimate resource potential similar to that of the WCSB. We analyze the impact on North American gas markets of the introduction of an additional low-cost supply from an unspecified, but non-Canadian, source beginning late in this decade.[5]

There are uncertainties also about other possible sources of supply: LNG, unconventional gas, and gas from the frontier regions of Canada. Our analysis suggests that the supply costs of these sources, together with environmental concerns in the case of LNG and transportation costs in the case of gas from the northern frontier regions, are likely to preclude them from becoming more than marginal sources of supply in the next two decades. We have not assessed the impact of any of these specific developments.

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4   The higher U.S. demand case was analyzed in the context of the Current Tech supply cost assumptions.

5   The possibility of a new low-cost source of gas supply was analyzed in the context of the High Tech supply cost assumptions.

FIGURE 6-4
Alberta Gas Supply Cost Comparisons
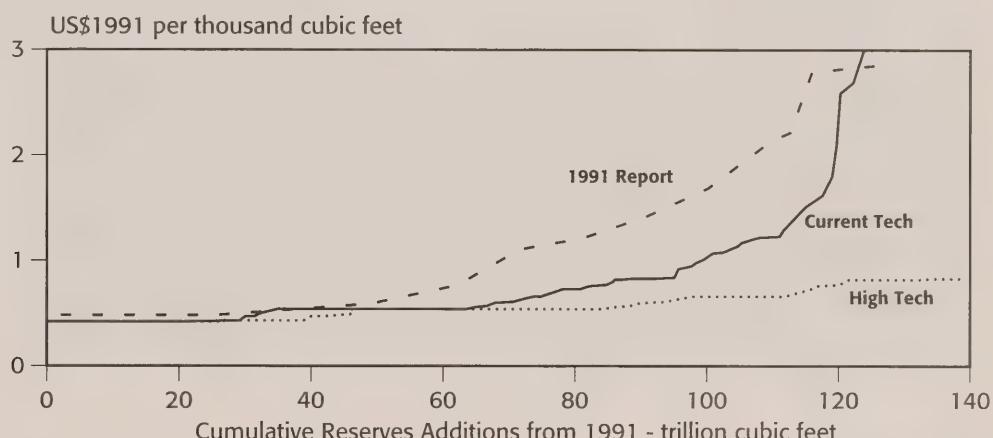
FIGURE 6-5
Alberta Fieldgate Gas Prices
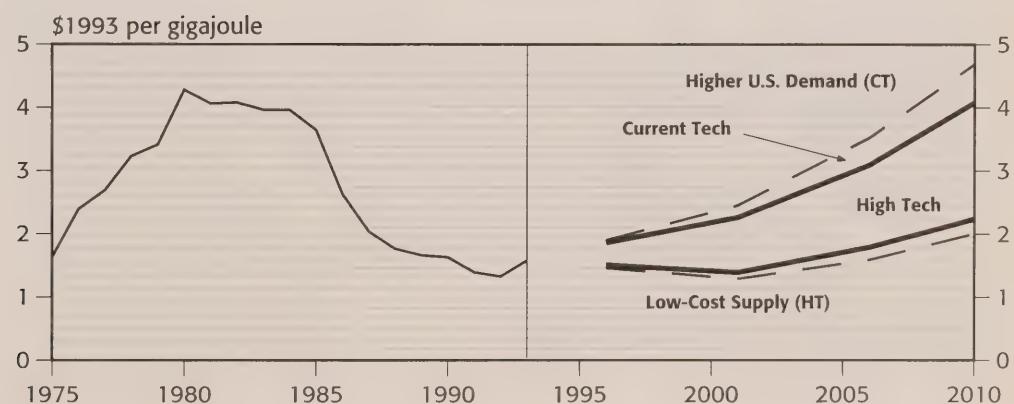
Analysis and Projections

Under all circumstances analyzed North American natural gas prices (Figure 6-5) rise from their current low levels. As would be expected, the High Tech supply case results in very modest price increases in both the U.S. and Canada. In this case the average annual rate of price increase in Canada would be close to two percent per year so that **fieldgate prices** reach about $2.25 per gigajoule by the end of the study period. The Current Tech supply analysis suggests that prices in both Canada and the U.S. would rise at about triple the rate for the High Tech case reaching a level of about $4.00 per gigajoule by the end of the study period compared with the 1993 level of $1.58. But even at this level the projected price in 2010 would be only modestly above the peak prices reached in the early 1980s.

In all cases examined, total **U.S. demand** for natural gas (Figure 6-6) rises over the study period. Not surprisingly, the increase is greater in a world characterized by relatively low natural gas supply costs and prices, and lower in a world characterized by more rapidly rising prices.

The higher demand case generates total annual U.S. gas use of over 25 trillion cubic feet in the years to 2005 but our analysis suggests levels as high as this are unlikely to be sustainable with the Current Tech view of supply. After 2005, rising prices of gas relative to oil increasingly result in energy users switching away from gas. Indeed, the decline of gas use in the latter part of

the study period is a characteristic of both cases analyzed using the Current Tech view of supply.

U.S. production growth (Figure 6-7) is strongest in the High Tech/low cost supply view of the world and weakest in the Current Tech view. With a High Tech view of supply U.S. production averages about 22 trillion cubic feet in the last five years of our study period compared to some 18 trillion cubic feet in 1992. In the Current Tech case, U.S. production is only about five percent higher in 2010 than it was in 1993.

These developments are mirrored in the projected evolution of **Canadian gas exports** (Figure 6-8) to the U.S. Canadian exports are highest in a high price, high U.S. demand world and lowest in a low price, supply-abundant world. Canadian gas is called on to a greater extent in the Current Tech/high demand analysis because the WCSB is relatively less developed than many U.S. basins and the cost of expansion of production from the WCSB is relatively low. Except for the case which combines the High Tech view with the assumption of an additional low cost North American supply, projected exports from Canada are generally at or above recent levels of about two exajoules per year.

Should an incremental source of low-cost supply, such as Mexico, enter the North American market, Canadian gas would face stiff competition. It is possible that, in these circumstances, Canadian exports could decline somewhat for a period of time. In our view, the development of such an incremental source is unlikely to occur before the turn of the century, in which case it

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FIGURE 6-6
U.S. Gas Demand
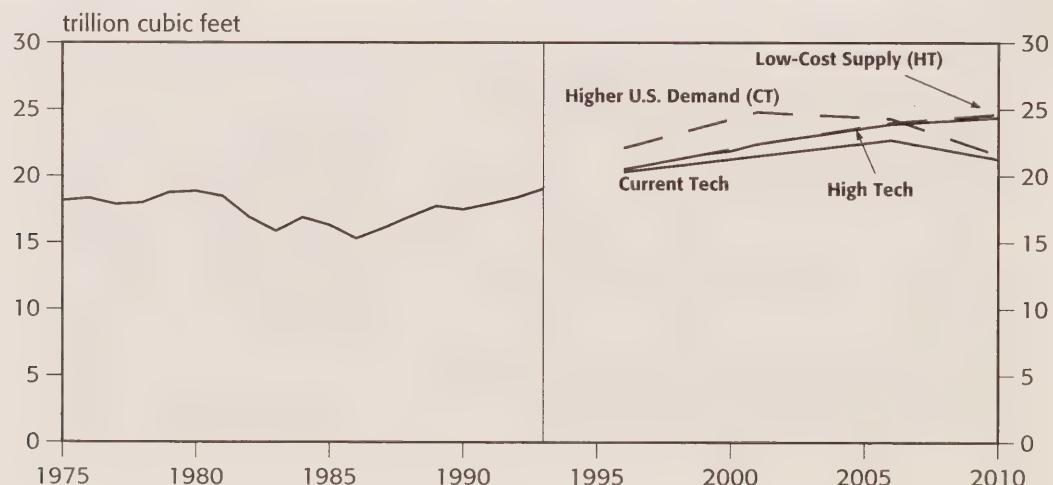
would have a modestly dampening effect on otherwise growing Canadian exports. Thus a plausible range for Canadian exports of gas over our study period appears to be between about two exajoules[6] per year, roughly the 1993 level, at the low end and about four exajoules per year at the high end.

In the Current Tech analysis, rising supply costs generate rising prices both in absolute terms and relative to our assumed world oil prices. Rising prices increasingly restrain demand for gas in North America and Canadian exports begin to decline towards the end of our study period.

Conversely, in the High Tech view, gas costs and prices are low in both the U.S. and Canada. In this world there are, however, large volumes of gas in the U.S. at lower costs than Canadian supply. Though this delays the time at which Canadian exports grow, both U.S. demand and Canadian exports continue steady growth through the end of the next decade.

Canadian exports continue to be concentrated in the Central region of the U.S. and in California. The Central region has the greatest potential for switching to alternative fuels in response to relative price changes so that, in the Current Tech/high price cases in which gas prices rise relative to those for oil, Canadian exports decline towards the end of the study period. Canadian

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6   One exajoule is approximately equal to .95 trillion cubic feet.

FIGURE 6-7
U.S. Gas Production
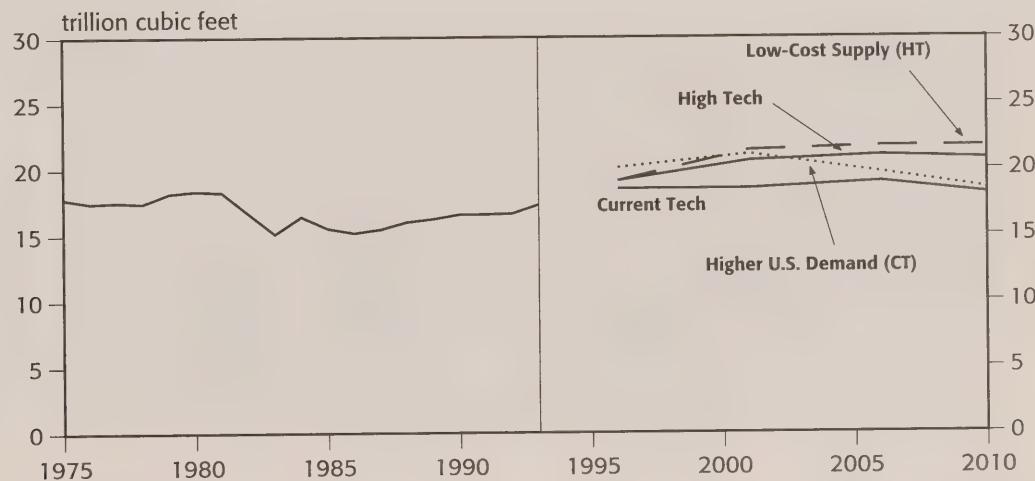
FIGURE 6-8
Canadian Gas Exports
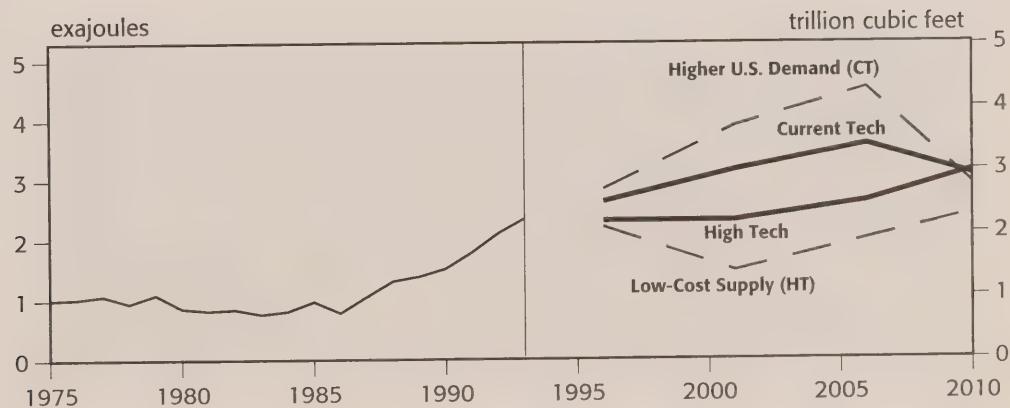
gas exports to California grow steadily over the study period because the state restricts the use of heavy fuel oil (Figure 6-9).

These projected levels and distribution of exports imply a substantial increase in pipeline capacity from Western Canada to the U.S. Midwest and to California.

As noted in Chapter 4 **Canadian demand** for natural gas (Figure 6-10) is sensitive to prices over the long term. Indeed, there is a difference of about one exajoule between our lowest and highest Canadian demand profiles. In the Alternative Macro analysis one can foresee Canadian primary demand for gas rising at a rate of close to three percent per year reaching as much as four exajoules in 2010. At the other extreme, should prices rise more rapidly, as in the Current Tech case,

demand would grow at a modest rate of about 1.5 percent per year to about three exajoules by 2000 and stabilize at that level until the end of the study period.

Canadian gas demand projections by Natural Resources Canada and the Canadian Gas Association fall within our range, tending to be closer to the Current Tech view in the earlier years of the study period (Figure 6-11).

Our analysis suggests that, in all cases, gas used in Canada will be supplied to a large extent from the WCSB. However, imports of gas to Eastern Canada are projected to rise gradually from 90 petajoules in 1992 to about 400 petajoules per year in both cases, although this level is achieved sooner in the High Tech case. This implies expanded pipeline capacity from the U.S. to

FIGURE 6-9

Canadian Gas Exports by U.S. Region
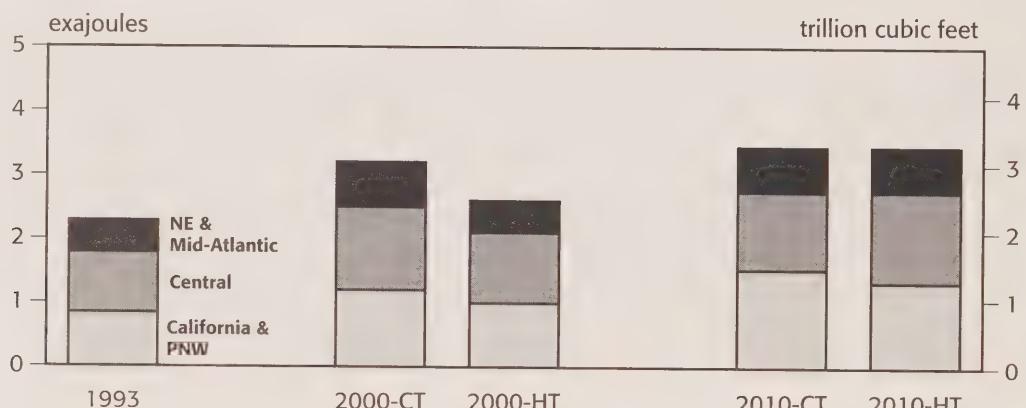
FIGURE 6-10

Canadian Gas Demand
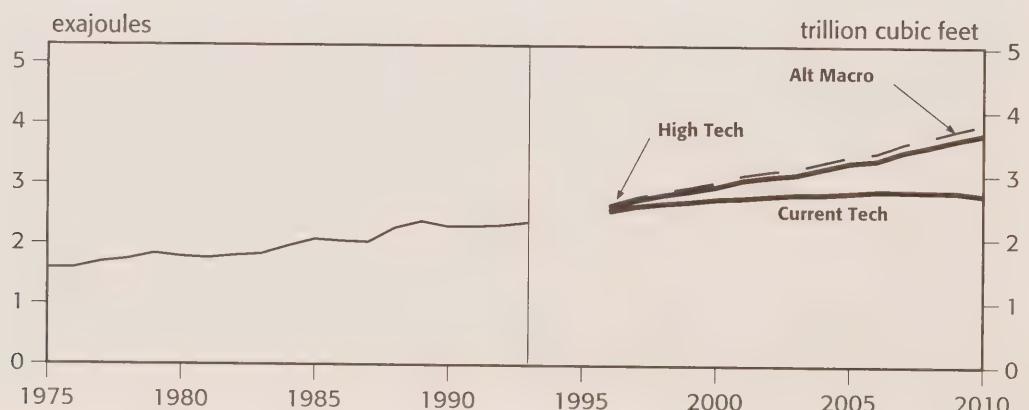
Ontario. Imports therefore could represent between 20 and 30 percent of Eastern Canadian supply by 2010.

The combination of export and domestic demand leads, under all scenarios, to rapidly rising **production of Canadian gas** (Figure 6-12) over the next two decades. As indicated, exports are the strongest influence and, under a combination of circumstances resulting from high electricity generation demand in the U.S. and the Current Tech view of gas supply costs, our analysis suggests that Canadian production could reach the neighbourhood of seven exajoules per year towards the end of our study period. The lowest production profile results from circumstances which combine the High Tech view of supply costs with increased

competition from a new low cost source of gas supply. Under that scenario, however, it seems likely that, in the longer run, there would be more sustained long-term growth in Canadian production.[7]

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7   It will be noted that, in some of the cases examined, our analysis suggests sharp changes in Canadian production over five year time periods. The analytical framework we use adopts a five year time interval for assessing the long-run equilibrium path of natural gas markets. It does not analyze the adjustment process by which markets move from one equilibrium to another. It is unlikely that, in fact, the balance between productive capacity and demand could be adjusted as rapidly as this. Our analytical results should therefore be interpreted as indicating directions of change in gas flows implied by the underlying assumptions and not as precise estimates of production of and demand for gas.

FIGURE 6-11
Canadian Gas Demand – Comparison of Projections
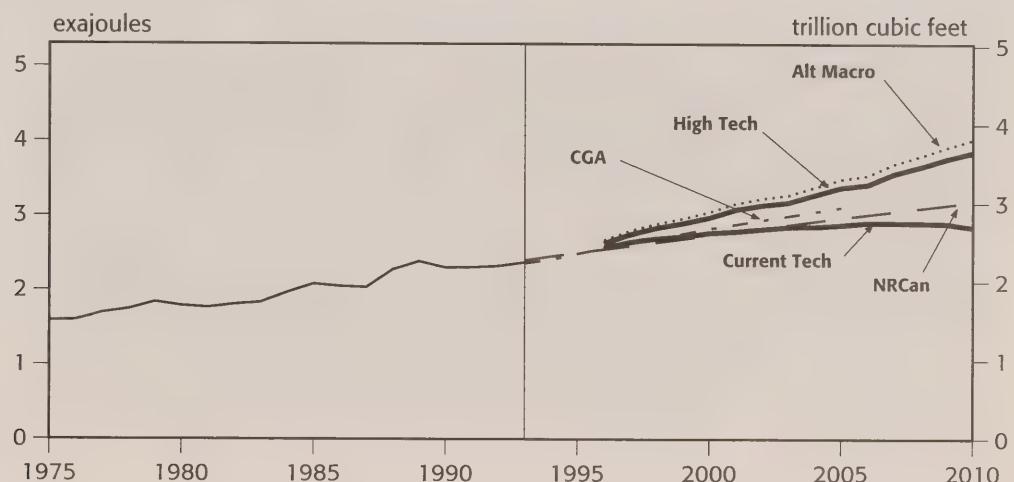
FIGURE 6-12
Canadian Gas Production
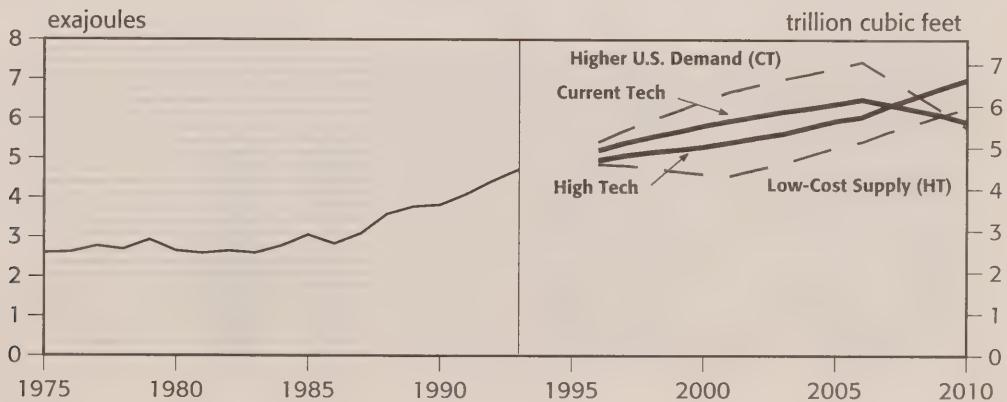
Our analysis suggests that almost all Canadian production is likely to continue to come from the WCSB over our study period. Alberta remains by far the largest source although British Columbia production increases appreciably from current annual levels of 0.5 exajoules to about 1.2 exajoules in 2010. In light of British Columbia's increasing share of total gas production, additional pipeline capacity will be required to transport B.C. gas eastward and/or southward.

Our price projections suggest that development of gas from northern frontier regions will not be commercially viable in the time period of our analysis. If prices were to follow the Current Tech track Sable Island gas, off the coast of Nova Scotia, becomes economically viable toward the end of the study period (2007). There are several potential development options with respect to the scale of development and disposition of the gas. These include gas sales to local and export markets, or using the gas to produce electricity for export. Notionally, we have assumed that the gas would be exported to the U.S. Northeast.

The supply of **natural gas liquids** follows a profile similar to that of natural gas production over the study period. The increases in NGL supply are, however, smaller than the projected increases in gas supply for the corresponding case. This reflects a gradual shift in gas supply towards B.C. which yields lower amounts of NGL than gas produced in Alberta. In both the Current and High Tech cases NGL production remains much higher than projected use in Canada so that exports are sustained at high levels throughout the study period.

FIGURE 6-13

Alberta Fieldgate Gas Prices – Comparison of Projections
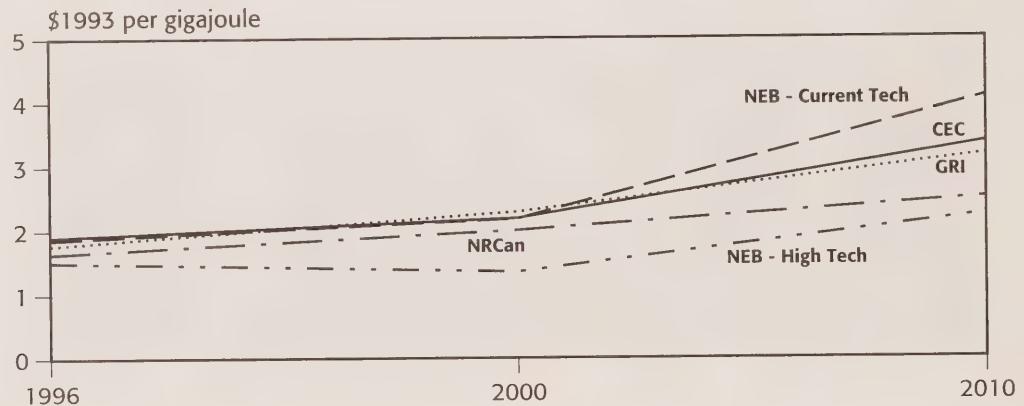
FIGURE 6-14

Canadian Gas Exports – Comparison of Projections
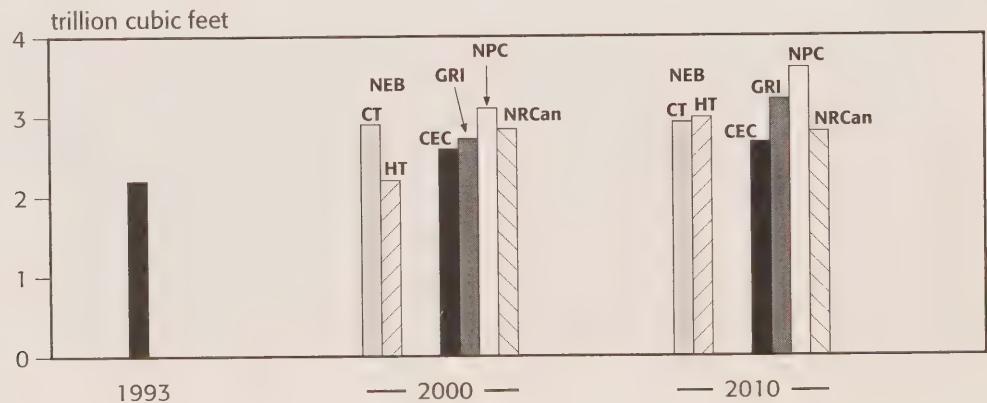
Growth in Canadian production in the Current Tech case implies reserve additions in the WCSB over our study period averaging about 4.5 exajoules per year. Reserve additions are somewhat higher when U.S. gas demand is at the "higher demand" level. This compares with average reserve additions of about 3.5 exajoules per year since 1987. The implications for exploration and development activity depend importantly on the impact of technological change on finding rates over the study period. In the Current Tech world, technology remains similar to that used now, although existing technology continues to improve. Gas-directed drilling is projected to increase rapidly from the 1993 level of two million metres to five million metres per year near the end of the study period. This level of drilling exceeds the previous peak of 3.5 million metres set in 1980.

In the High Tech world, reserves additions and drilling activity are difficult to analyze. Since drilling and production technology can be expected to change in unknown ways, the relationship between reserves and production may well be quite different from what it is using today's techniques and implying a quite different, and unknown, pattern of reserve additions for a given level of production. Thus it becomes inherently impossible to generate estimates of activity levels without making additional assumptions about the impact of technological change.

Our projections of gas fieldgate prices and exports are compared with those of other analysts in Figures 6-13 and 6-14 respectively.

Because different analysts use different assumptions about key underlying variables such as world oil prices and economic growth, the projections are not directly comparable. They do, however, indicate directional similarities or differences among projections. It is interesting to note that, whereas projections of production and Canadian gas exports tend to be similar, there is a wider range of views about the prospects for wellhead prices. Our understanding is that this range is predominantly due to different assumptions about the future of world oil prices, the extent of substitution between gas and oil and about the outlook for gas supply costs.

Our analysis has been designed to assess the impact of alternative combinations of assumptions about the time paths of key underlying variables on Canadian gas supply, demand and prices. We have not analyzed the implications of all plausible combinations, nor do we present any one combination as being more probable than another. Views expressed about gas supply during the technical consultations tended to be closer to the Current Tech case.

Clearly developments in Canadian gas production and in North American gas prices will be profoundly affected by gas supply costs, U.S. demand for gas and by the competition generated by supply developments in the U.S. and Mexico.

CRUDE OIL

Our analysis of the prospects for the supply and disposition of Canadian crude oil is based on alternative assumptions about the evolution of oil supply costs due to advances in exploration and production technology, and the impact of world oil prices.

Canada's oil resources consist of light and heavy conventional oil and unconventional crude oil in the form of bitumen in the oil sands (Table 7-1). Conventional crude oil is produced from subsurface reservoirs under natural reservoir pressure and, in some cases, using production techniques designed to improve flow rate and overall oil recovery. In contrast, bitumen is typically too viscous in its natural state to flow to a production well; a substantial quantity of external energy must be added to the reservoir through steam injection to initiate flow. Integrated mining is an alternative method to extract oil from shallow deposits.

Conventional oil consists of light and heavy oil in western Canada and light oil resources found in frontier regions in the north and offshore. Light and heavy conventional crude oil resources make up seven percent of Canada's in place oil resource inventory. Most of the estimated recoverable resources of light oil in the WCSB have already been discovered, indicating the basin's mature state of development.

Further, about 70 percent of the estimated discovered WCSB light oil resources have already been produced. For the frontier areas, a small fraction of the estimated resource has been discovered and undiscovered resources are recognized as a possible source of future supply. For heavy oil, technological advances have significantly increased the estimates of recoverable quantities. Roughly 50 percent of the discovered resource remains to be produced; we estimate

TABLE 7-1

Crude Oil and Bitumen Resources, Year-End 1992

(million cubic metres)

		Recoverable Resources			In Place Resources
		Discovered		Undiscovered	
		Cumulative Production	Remaining[1] Discovered Resources		
Conventional Crude Oil					
Light	- WCSB	1 965	797	519	10 181
	- Frontier	19	561	3 582	14 276
Heavy		410	455	260	5 910
Total	- **Conventional**	**2 394**	**1 813**	**4 361**	**30 367**
Bitumen					
	- Mining	210	9 790	0	24 000
	- In Situ	59	38 941	0	376 000
Total	- **Bitumen**	**269**	**48 731**	**0**	**400 000**

1. Remaining Discovered Resources include Remaining Established Reserves and Other Discovered Resources which are currently estimated to be recoverable using known technology but which have not been recognized as established reserves because of uncertain economic viability.

Source: NEB, ERCB

that two-thirds of this amount will be available using current improved recovery methods.

Bitumen resources are very large compared to conventional resources representing 93 percent of Canada's estimated in place resources. We assume that all of the in place bitumen resource is discovered, since the location and characteristics of the oil sands are reasonably well known, and future discoveries are assumed to be negligible.

About one-fifth of the recoverable bitumen resource is close to the surface. For this portion of the resource, the production process involves surface mining of the oil sands, followed by separation of the bitumen from the oil sands in a plant. The bitumen is then upgraded on site into synthetic crude oil for sale to refineries. Commercial mining operations began in 1967, and two integrated mining plants are now in operation.

The other four-fifths of the recoverable bitumen resource is too deep to be mined and must be extracted directly from the subsurface reservoir. "In situ" production techniques typically involve the injection of steam into the oil sand in order to reduce the viscosity of the bitumen, and to provide the energy to produce it through a vertical or horizontal well. Roughly 80 percent of the estimated recoverable resource is believed to be producible with in situ methods.

Total **Canadian oil production** has shown an upward trend since 1982. Between 1990 and 1993, the increase was nearly 10 percent, mainly due to increased production of conventional heavy oil and synthetic oil (Figure 7-1). In 1993, total production of 291 thousand cubic metres per day was comprised of approximately 49 percent of light oil, 29 percent of heavy oil (including bitumen), 14 percent of synthetic oil and eight percent of pentanes plus.

Production has increased, despite weakening prices, because of a significant decline in supply costs for various types of crude oil. These costs have fallen by up to 25 percent since 1990 as a result of industry restructuring and rapid technological progress. Perhaps the most important of the technological developments has been the application of horizontal drilling techniques which has led to an exponential growth in the number of horizontal wells in recent years. Compared with vertical wells, horizontal wells provide greater reservoir contact leading to accelerated production and somewhat higher recovery. In addition, there have been improvements in seismic techniques, drill bits and drill rigs, production equipment and recovery technologies. For bitumen, there has been impressive technological progress in the extraction and separation of bitumen from oil sands.

Projections of Canadian oil supply, as for natural gas, have been steadily revised upward by the Board and other analysts. This suggests that the substantial impact of technological advances, such as horizontal drilling and improved exploration techniques, had not been fully anticipated. Consequently, technology has become a focal point of oil supply analysis.

Canadian Oil Supply

We have assessed the prospects for Canadian oil supply under two alternative cases in a manner similar to that adopted for natural gas. The Current Tech case

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FIGURE 7-1
Canadian Crude Oil and Equivalent Production

thousand cubic metres per day
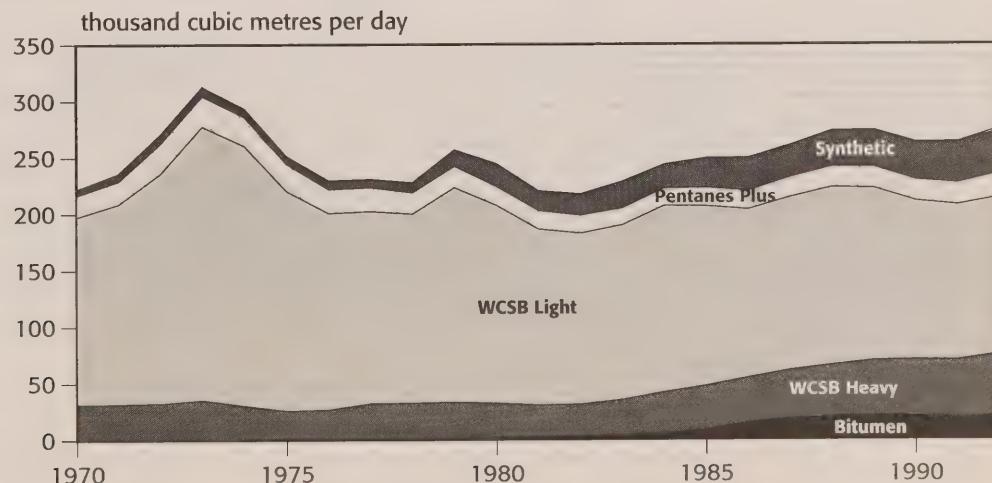
assumes oil supply costs associated with technologies that are currently in use or which have already been extensively tested and are close to becoming commercially viable. The other case, High Tech, incorporates oil supply costs associated with technologies that are in the early stages of research. Our cost estimates in this case are based on consultations with the industry, assessment of historical trends and our own judgement.

To account for price uncertainty, we have also assessed the implications of US$15 and US$30 prices for Canadian oil supply under the Current Tech assumptions[1].

Changes in gas prices have an impact on supply costs for in situ bitumen projects which use natural gas for steam generation. Gas prices are higher in the Current Tech case than the High Tech case, reflecting the difference in assumptions for gas supply costs described in Chapter 6.

The supply projections for conventional oil in the WCSB are based on the assumption that the supply costs for new discoveries will rise gradually in both cases as discoveries are smaller and less accessible. The rate of cost increases is more modest in the High Tech case because of the impact of technological improvements. Supply costs for development of discovered resources are about US$4 per barrel less than in the Current Tech case.

The supply projections for other sources, such as Alberta's oil sands and the frontier, assume that the costs could increase slightly in the Current Tech case and fall by up to 20 percent by the end of the projection period in the High Tech case. This is premised on the view that, unlike conventional oil in the WCSB, the resource base and associated technologies are far from reaching a mature stage of development.

We have estimated ranges of **supply costs** for various types of crude oil in major producing areas. To bring these costs to a common basis we made adjustments for transportation costs and different oil qualities. The resulting cost estimates can be taken to represent the prices required to make the development of each source economically viable. The required prices are estimated for the two cases in the year 2000 (Figure 7-2).

As expected, the required prices are consistently lower in the High Tech case than in the Current Tech case for all six supply categories considered. The reductions generally range between 10 and 20 percent, and are the highest for steam-assisted bitumen projects which, in the High Tech case, benefit from gas prices considerably lower than in the Current Tech case.

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1 In both the Current Tech and High Tech analysis world oil prices rise from $19 to $23 per barrel by the end of our study period. Our high price analysis was conducted under the assumption of current technology; clearly supply would be higher than this if the high price were matched with the High Tech assumptions.

FIGURE 7-2
Required Oil Prices at Market[1] – Year 2000
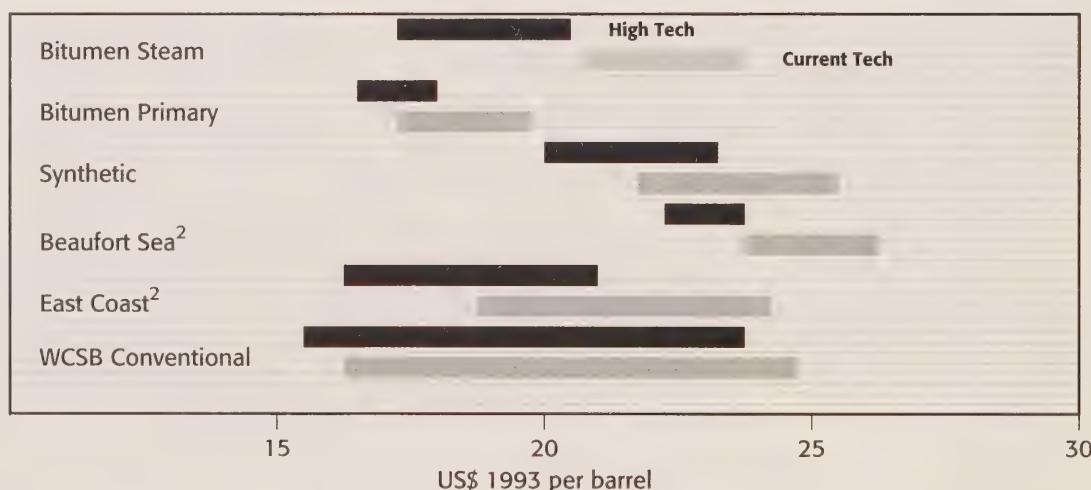
1 Prices needed to cover supply costs plus the allowances for transportation costs and lower quality of bitumen. Conceptually, these prices use Cushing as a basing point.
2 These required prices do not include exploration expenditures.

The comparison among the six categories suggests that conventional oil in the WCSB and bitumen produced using primary recovery continue to be the lowest-cost sources of Canadian oil supply. The highest-cost sources, by contrast, include frontier discoveries and synthetic oil produced by integrated oil sands mining plants, both of which require prices in the range of US$20-26. Development of these resources is also very risky because of their high capital costs and long lead times. Frontier oil in northern basins is additionally burdened with high costs of transportation.

Although supply costs for oil sands and East Coast frontier projects are similar, other considerations may tend to give the oil sands a competitive edge over the frontier. These include a larger, better defined and more accessible resource base, and a greater potential for future cost reductions through the application of new bitumen extraction and upgrading techniques.

In comparison to our sustainable range, only conventional oil from Western Canada is viable at prices near US$15. Below US$15, we recognize that some exploration will continue targeting low cost plays. Within the US$15-26 range, the amount of production and the number of economically viable sources is sensitive to price changes. Prices above US$26 are sufficient to justify development of each of these Canadian sources.

FIGURE 7-3
Western Canada Light Oil Production
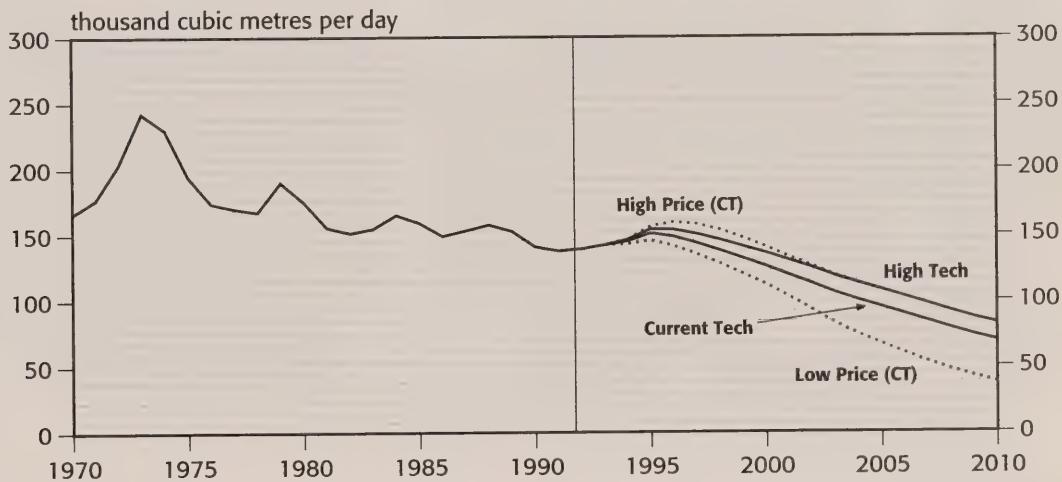
FIGURE 7-4
Frontier Oil Production
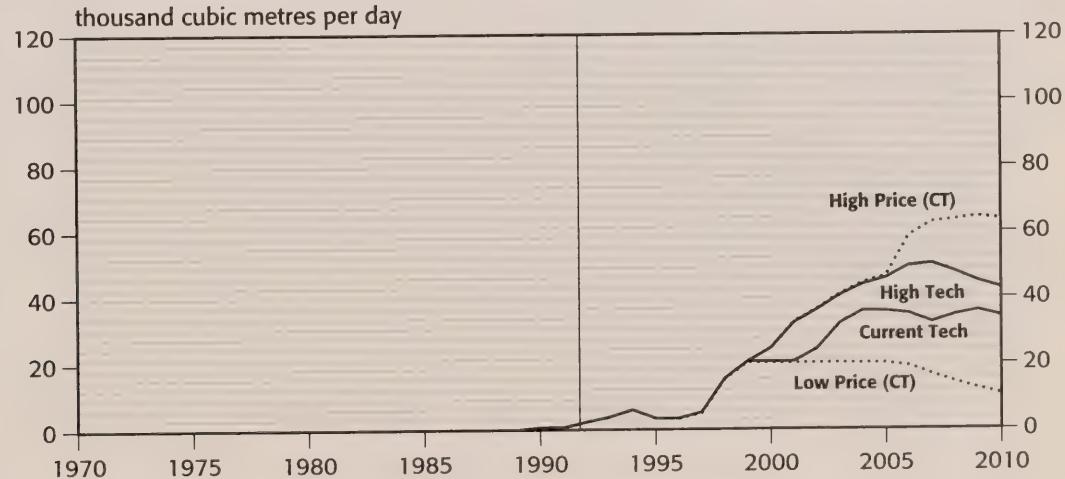
The supply of **conventional light oil** from Western Canada is projected to increase to a maximum rate of roughly 150 thousand cubic metres per day in the late 1990s, based on projections of aggressive application of horizontal wells (Figure 7-3). Thereafter, the long term declining trend resumes, bringing production to a range of 40 to 80 thousand cubic metres per day by 2010. The state of resource depletion in the WCSB suggests that light oil production is unlikely to be sustained near current or peak projected rates, even under the High Tech view of technological progress.

Our analysis suggests that **frontier production** could become an important component of Canadian light oil supply towards the end of our study period (Figure 7-4). At prices near the lower limit of the sustainable range, Hibernia is the only major source of frontier supply through the study period as no other projects are commercially attractive. However, at higher price profiles, or with the development of improved technology, a number of other East Coast offshore projects, such as Terra Nova and Whiterose, could become viable. Production from far northern frontier regions will occur only at prices near the upper limit of the sustainable range, and then only in the Mackenzie Delta/Beaufort Sea.

Heavy crude oil production from conventional areas has been rising steadily since the early 1980s as producers responded to increased market opportunities (Figure 7-5). The inventory of remaining established resources has expanded by 30 percent as a result of active exploration and development programs. Heavy oil production has accelerated in recent years due to the successful application of horizontal drilling techniques. The number of horizontal wells in western Canada has increased rapidly from 40 in 1989 to close to 900 in 1993. We anticipate further increases as the application of this technology expands.

Our projection reflects the view that the pace of activity in horizontal drilling will result in increased reserves additions and a rapidly accelerating rate of production of conventional heavy crude oil over the next few years. However, accelerated production leads, eventually, to a steep decline, even under the High Tech and high price assumptions. As existing reserves are depleted, it will require progressively more effort to maintain the high production levels currently being projected. Nevertheless, it is possible that over the study period, technological progress at a pace faster than that of recent years could further improve recovery factors for conventional heavy crude oil. This would allow production to be maintained at levels higher than projected.

Our projections imply a continuation of oil-directed drilling for light and heavy oil at current levels. Exploratory drilling remains at about 1 000 and 1 200 wells per year in the Current and High Tech cases respectively. Development drilling, which has averaged about 2 500 wells per year in recent years, could average 3 000 wells per year over the study period.

Bitumen production would tend to increase if world oil prices were sustained at levels near the middle

FIGURE 7-5
Western Canada Heavy Oil Production*

thousand cubic metres per day

* Conventional heavy oil, excludes bitumen
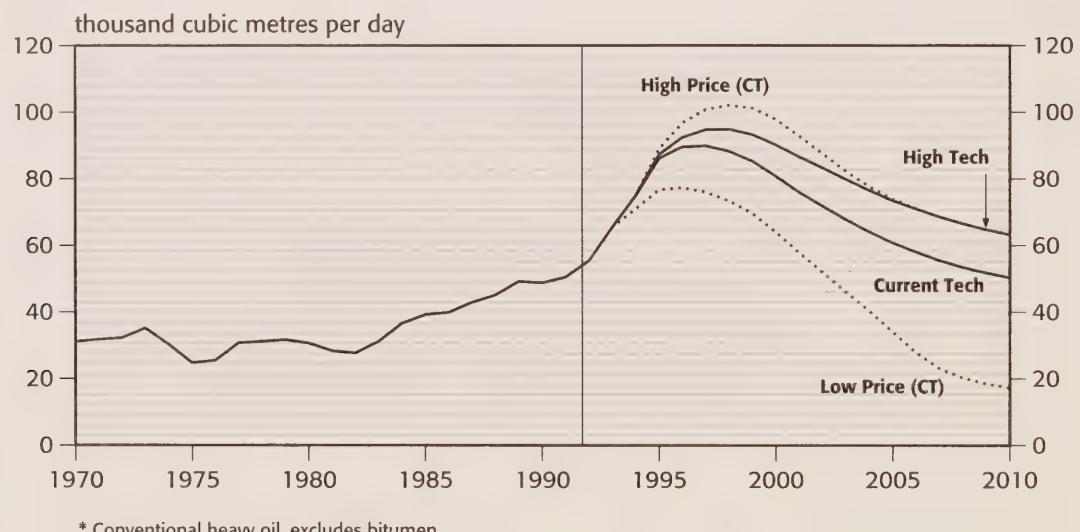
of our projected price range, or if the pace of technological advance and cost reductions continues (Figure 7-6).

In a world in which continued technological progress is coupled with mid-range oil prices, it is possible to envisage total bitumen production from in situ production and mining plants rising from about 60 thousand cubic metres per day in 1993 to upwards of 140 thousand cubic metres per day by 2010. In the Current Tech case, total bitumen production is roughly 100 thousand cubic metres per day in 2010 since higher natural gas prices restrain in situ bitumen production. These projections suggest that bitumen production would decline only if world oil prices remained at low levels and no technological progress occurred.

Heavy crude oil and bitumen from oil sands are exported for use directly in refineries in the U.S. northern tier which are equipped to process it, or upgraded to yield synthetic crude oil.

Synthetic crude oil is produced from bitumen at integrated mining plants and from bitumen and heavy oil at stand-alone upgraders (Figure 7-7). The prospects for

FIGURE 7-6
Bitumen Production*

thousand cubic metres per day

* Includes total "in situ" bitumen production plus synthetic oil production from integrated mining plants
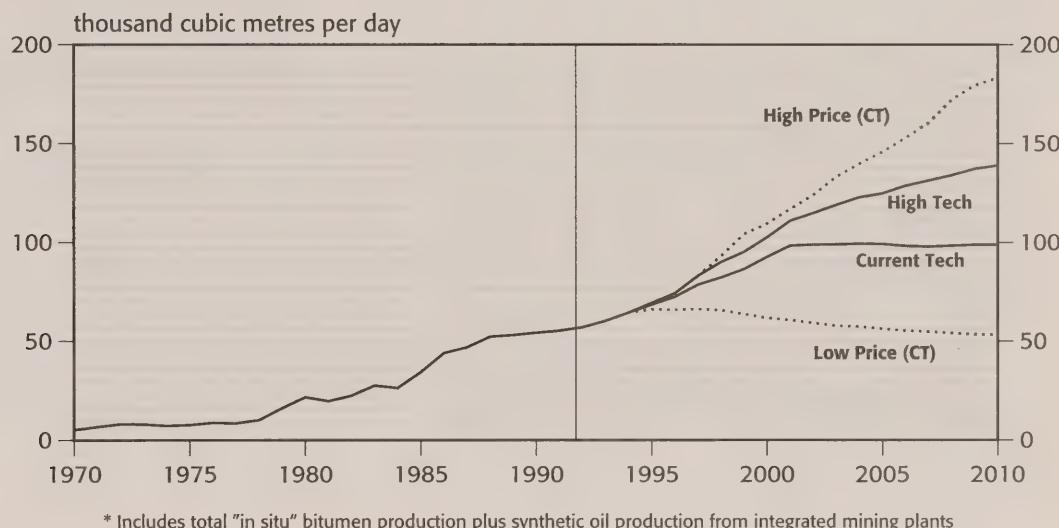
FIGURE 7-7
Synthetic Oil Production*

thousand cubic metres per day

* Includes synthetic oil from mining plants and upgraders
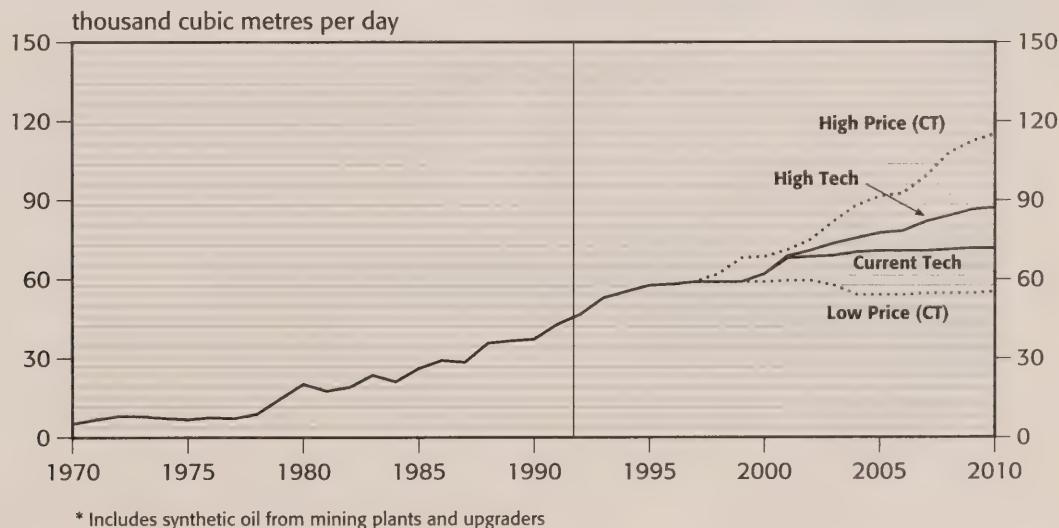
expansion of synthetic crude oil production from integrated plants depend on world oil prices being at high levels or on dramatically reduced costs.

The prospects for **upgrading** at stand-alone upgraders and refineries in Canada are critically dependent on the Canadian dollar price differential between light oil and heavy crude or blended bitumen. Upgrading will only be profitable if this price differential is greater than the cost of upgrading. Heavy crude oil price discounts have recently been as small as $4 per barrel, whereas the price differential required to cover the costs of new upgrading facilities are generally estimated to be between $7 and $9 per barrel. Thus, expansion of upgrading capacity would only be worthwhile if the price differential between light and heavy crude were to increase appreciably from current levels.

In the North American context our analysis suggests that price differentials would only increase appreciably in the High Tech case, in which technological progress in heavy crude oil production leads to dramatic increases in production. Production levels of this magnitude would tend to reduce heavy oil prices in Canada as this oil sought markets progressively more distant from the producing basin. These circumstances could, therefore, encourage expansion of upgrading facilities in Canada.

Current production of synthetic crude oil from integrated mining plants and stand-alone upgraders is about 53 thousand cubic metres per day. Our analysis suggests that production could rise modestly to about 55 thousand cubic metres per day at the low end of the price range and increase to some 115 thousand cubic metres per day at the high end. At the low end, production increases come entirely from improvements in the operation of existing integrated plants. At the high end, production could occur in a number of ways: from expansion of upgrading facilities either at existing integrated plants or at stand-alone upgraders such as Lloydminster, or from the addition of upgrading facilities at existing Alberta refineries.

In summary, under most conditions analyzed total Canadian crude oil production increases from recent levels; the largest increases occur under conditions of rapid technological progress and/or relatively high prices (Figure 7-8). The composition of production could shift from conventional sources in the WCSB towards unconventional and frontier sources.

There is a clear tendency for projections of crude oil supply in Canada to drift upward over time. This is illustrated for the case of conventional light crude oil in Figure 7-9 which compares the production projections of this report to the year 2000 with previous Board projections. The upward drift reflects many of the phenomena that have been discussed earlier in this chapter and in the chapter on natural gas. These include continuous technological progress in finding and production techniques, improved geological knowledge, and increasing efficiency in the use of those techniques as companies have had to compete in a world of much lower prices. Our current projections for Western Canada total crude oil and equivalent production are compared with others in Figure 7-10.

FIGURE 7-8
Total Crude Oil and Equivalent Production
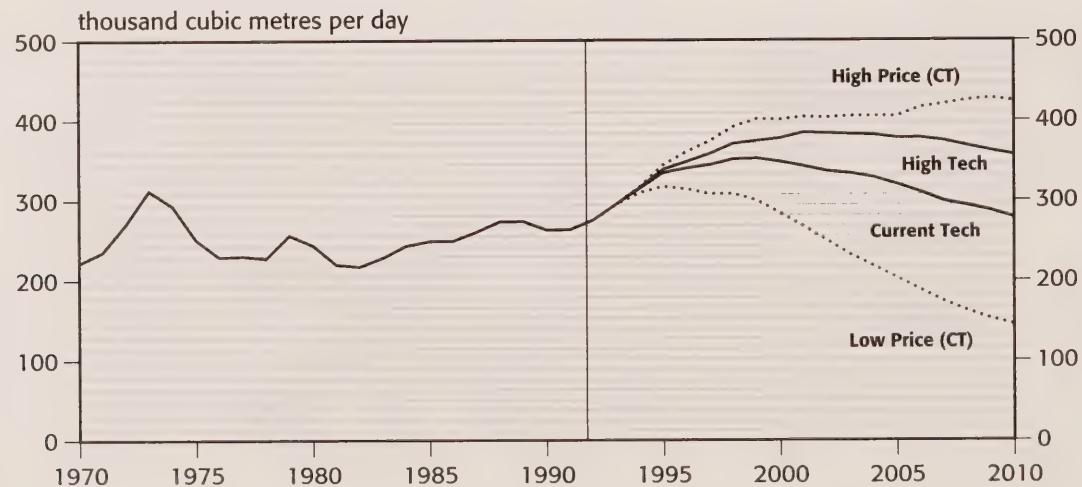
Disposition of Crude Oil

The disposition of Canadian crude oil production is determined by the degree to which Canadian crude can compete on the basis of price, quality and availability in individual market areas in Canada and the U.S. northern tier.

At present, most heavy crude oil is exported. We see no reason for this pattern to change since we do not expect a significant increase in the domestic use of heavy oil in Canada over the study period. As a result, the export profile follows the production profile. In the High Tech case, exports of heavy crude increase dramatically, nearly doubling from 1992 levels. In the Current Tech case, heavy oil exports will also tend to increase through 1999, although more modestly than in the High Tech case.

To a considerable extent, development of Canadian heavy oil will be contingent on producers' assessments of market opportunities, particularly in the U.S., and related netbacks. The consensus of analysts at present appears to be:

- There is unlikely to be a large increase in product demand in U.S. northern areas.

- U.S. indigenous production now supplying refineries in the U.S. northern areas is declining, providing an opportunity for Canadian heavy crude to capture additional markets.

- The northern area of the U.S. has, it appears, the potential to expand heavy oil processing capacity at costs which are broadly consistent with low light-heavy price differentials.

FIGURE 7-9

Conventional Light Crude Oil Production, WCSB – Actual and Projections
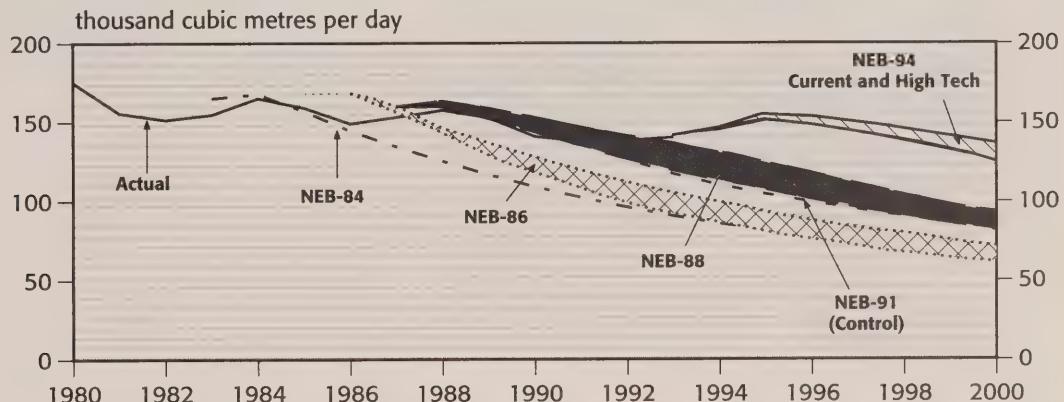
FIGURE 7-10

Crude Oil and Equivalent Production, WCSB – Comparison of Projections
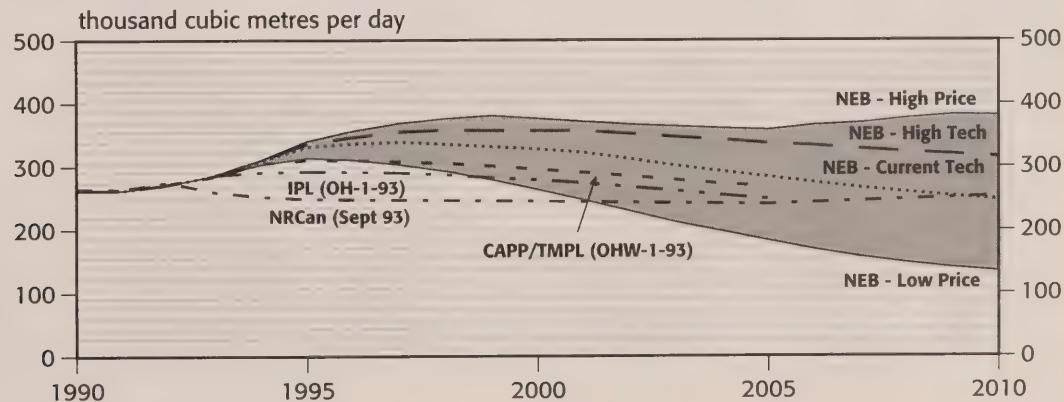
- U.S. refiners have indicated an intention to maintain and increase the use of Canadian supplies. However should Canadian production approach levels projected in the High Tech analysis it seems likely that new markets such as the Wood River, Illinois, refining area would have to be reached.

The extent to which Canadian light crude oil production is used in Canada or exported depends on other factors:

- Our analysis of the demand for refined petroleum products in Canada, reported in Chapter 4, suggests that growth is likely to be modest.

- It seems likely that currently existing refinery capacity, together with a continuation of recent levels of product exports and imports, will be largely adequate to produce the product slate required.

- The characteristics of the oil produced from the Hibernia development on Canada's East Coast are not currently compatible with existing refinery facilities; all of this production is likely to be exported.

- Oil produced from other potential East Coast developments could be used in eastern Canadian refineries.

Refining centres in Ontario historically obtained most of their crude oil supply from western Canada, whereas those east of Montréal have been supplied primarily from offshore sources through water-borne imports. Until the early 1990s, Montréal refineries obtained substantial quantities of crude supply from both western Canada (through the IPL Sarnia-Montréal Pipeline extension) and from foreign sources (via the Portland-Montréal Pipeline system). At present, the Montréal refineries receive only small volumes through the IPL extension. Whether the extension continues to be used to ship western Canadian crude to Montréal, is deactivated, or is reversed to allow foreign oil to flow to Ontario refineries will depend on the delivered costs of foreign and Canadian oil to refineries in Ontario and Montréal.

Exports are primarily heavy crude oil whereas imports are almost all light crude oil. In our analysis, Canada remains a net exporter of crude oil in total over most of the study period although the magnitude of such exports is substantially greater in the High Tech than in the Current Tech case (Figure 7-11). At prices lower than the mid-point of our sustainable range, Canadian production declines sufficiently rapidly that Canada becomes a net importer towards the end of the study period.

FIGURE 7-11
Canadian Crude Oil Exports and Imports

Chapter 8
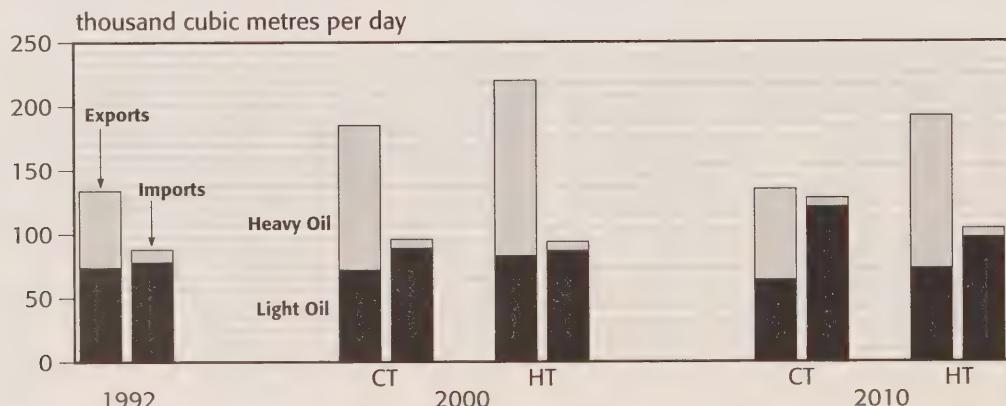
IMPLICATIONS OF ENERGY PROJECTIONS
FOR ATMOSPHERIC EMISSIONS

Atmospheric emissions can have an important influence on the environment. These emissions result to a large extent from the production and use of fossil fuels. The emissions we consider are those associated with the greenhouse effect, with the formation of acid rain and with the degradation of air quality (low-level ozone and smog). Emission amounts are related to fuel type and, for some gases, to the combustion technology used. They are, therefore, directly linked to the energy projections discussed in previous chapters[1].

The production, transportation, and use of fossil fuels result in the emissions of various gases:

- When fossil fuels are burned, carbon dioxide, nitrous oxide, sulphur dioxide and nitrogen oxides are formed and discharged to the atmosphere. Some naturally occurring carbon dioxide is also released when hydrocarbons are produced.

- Methane escapes to the atmosphere when natural gas and coal are produced and when natural gas is incompletely burned.

- Volatile organic compounds (VOC) are emitted to the atmosphere during combustion of fossil fuels and from the evaporation of liquid fuels during their production, storage and handling.

The relative importance of the energy sector in contributing to these emissions is shown in Figure 8-1. Carbon dioxide emissions are far greater than any of the others and it is estimated that 90 percent of the man-made carbon dioxide emitted in 1990 in Canada came from the energy sector. Of the other gaseous emissions, energy-related sources account for over 90 percent of nitrogen oxide, about 45 and 55 percent of sulphur dioxide and VOC respectively, and 35 percent of methane emissions.

Though carbon dioxide emissions are an inherent part of the combustion process, emissions of other gases are related to the technology used to burn them. Emissions projections of these gases are, therefore,

---

1   Gaseous emissions are calculated by multiplying the energy production and use projections by emissions factors (rates of emissions per unit of production, transmission or combustion) as estimated by Environment Canada and NRCan. To calculate emissions in the upstream oil and gas sector, results of studies completed for Environment Canada and CAPP were incorporated, and assistance was received from ERCB.

FIGURE 8-1

Gaseous Emissions from Man-Made Sources – 1990

(million tonnes)
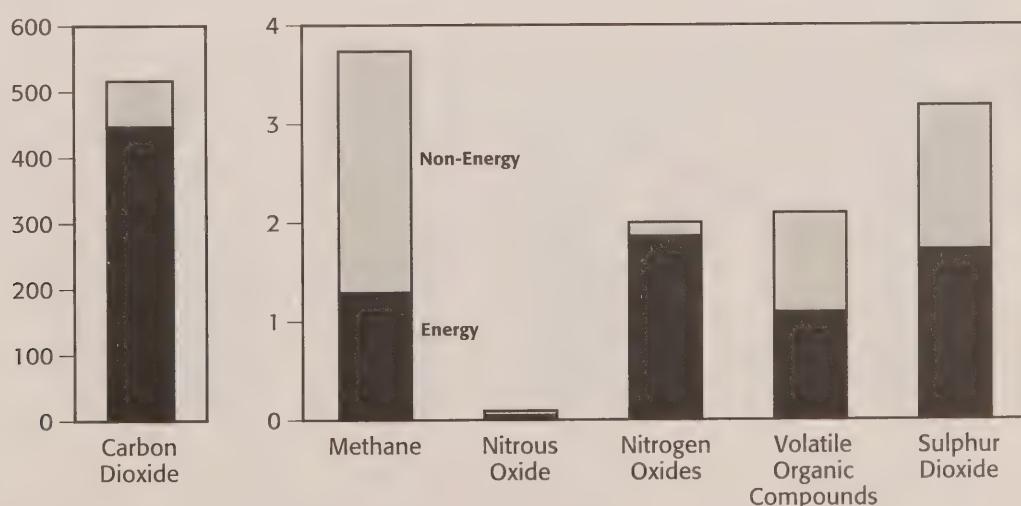
subject to greater uncertainty than are projections of carbon dioxide emissions.

Carbon dioxide, methane and nitrous oxide are the greenhouse gases associated with global warming. Their effects on the atmosphere have been the subject of much international discussion in recent years and resulted in the adoption, in May 1992, of the United Nations Framework Convention on Climate Change. The ultimate objective of this Convention is to stabilize atmospheric concentrations of greenhouse gases.

As part of its commitment under the Framework Convention, Canada has prepared a national report[2] which contains an extensive discussion of climate change issues and their relationship to greenhouse gas emissions. The report provides estimates of the rates at which greenhouse gases currently are emitted into the atmosphere, projects future trends in these rates and assesses the impact of policies and measures to limit greenhouse gas emissions in Canada.

Sulphur dioxide and nitrogen oxides contribute to the formation of acid rain which can have important regional effects on vegetation and wildlife. Control of sulphur dioxide emissions has been addressed in a Canada-U.S. protocol and a series of federal-provincial agreements. Volatile organic compounds, in combination with nitrogen oxides, have a local effect, contributing to the formation of ozone in the lower atmosphere and urban smog in areas of industrial activity and high population density. Measures to reduce emissions of oxides of nitrogen and VOCs are being developed through Canada's Management Plan for

Nitrogen Oxides and Volatile Organic Compounds which was adopted in 1990 by the Canadian Council of Ministers of the Environment.

Emissions Estimates

We have made estimates of the level of greenhouse gas emissions which could arise from our energy projections using the emissions factors developed by the Departments of Environment and Natural Resources in preparing the projections included in the Climate Change Report. We calculated the implications of three energy projections for emissions: the Current and High Tech cases and the Enhanced Cooperation case in electricity[3]. Our projections for carbon dioxide and methane[4] are shown in Figures 8-2 and 8-3 respectively. For comparison, these figures include the projections of Natural Resources Canada[5] and those contained in the Climate Change Report.

Our projections, like those in the Climate Change Report, imply that carbon dioxide and methane

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2 Environment Canada, *Canada's National Report on Climate Change*, Ottawa, 1994.

3 For sectors other than electrical utilities, emissions estimates used in the enhanced utility trade case are those of the Current Tech case.

4 Nitrous oxide contributes to a small extent to total greenhouse gas emissions. Because there is great uncertainty about emissions factors for this gas, we have not projected these emissions.

5 Natural Resources Canada, *Canada's Energy Outlook, 1992-2020*, September 1993.

FIGURE 8-2
Carbon Dioxide Emissions

1 Enhanced Cooperation in electricity
2 The range in *Canada's National Report on Climate Change* is based on the NRCan case. The range illustrates the effect of changing key variables affecting energy demand.
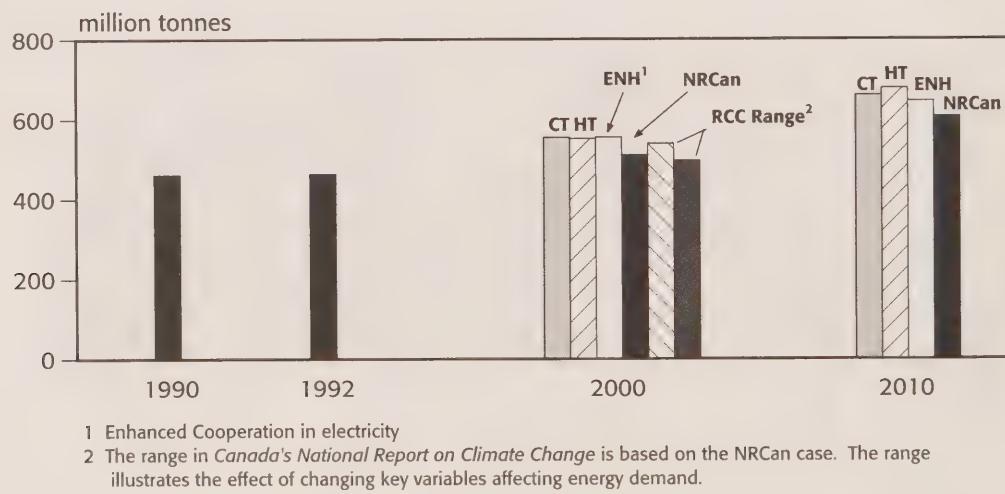
emissions will continue to rise with growing use of fossil fuels over the study period.

There is little difference between the Current and High Tech projections of carbon dioxide emissions. Our projections are slightly higher than the others shown for both the years 2000 and 2010. This results from the higher projected levels of fossil fuel production and use in our analysis.

Our estimates of methane emissions are higher at the end of the study period, in both Current and High Tech cases, than those of Natural Resources Canada. This results from higher projected levels of methane vented from coal mines and higher gas production in our analysis.

Estimates of nitrogen oxides, sulphur dioxide and volatile organic compounds associated with our energy projections are shown in Figure 8-4. Emissions of nitrogen oxides rise to a moderate extent; increases attributable to higher overall energy use are muted by lower emissions from automobiles as engine technology improves.

Energy related emissions of VOCs decline over the study period due to improved emissions controls in the transportation sector. Emissions in the High Tech

case are higher in 2010 than in the Current Tech analysis because emissions attributable to the upstream oil and gas sector are higher in the former case.

Emissions of sulphur dioxide decline substantially over the study period. This results from a large decline in emissions from the generation of electricity, in response to legislated limits on emissions, partially offset by a rise in emissions associated with higher natural gas production.

Emissions of carbon dioxide, nitrogen oxides and sulphur dioxide are lowest in the enhanced electricity trade case. In that case large amounts of fossil-fuelled electricity generation are displaced by hydro-electric generation.

It is important to reiterate that, unlike carbon dioxide emissions, the rate of emissions associated with methane, nitrogen oxides, sulphur dioxide and the VOCs can be controlled by altering the technology of producing and/or using fossil fuels. Therefore our projections of emissions of these gases are heavily conditioned by the fact that we assumed a continuation of current technology relating to energy production and consumption throughout our projection period.

FIGURE 8-3
Methane Emissions

million tonnes
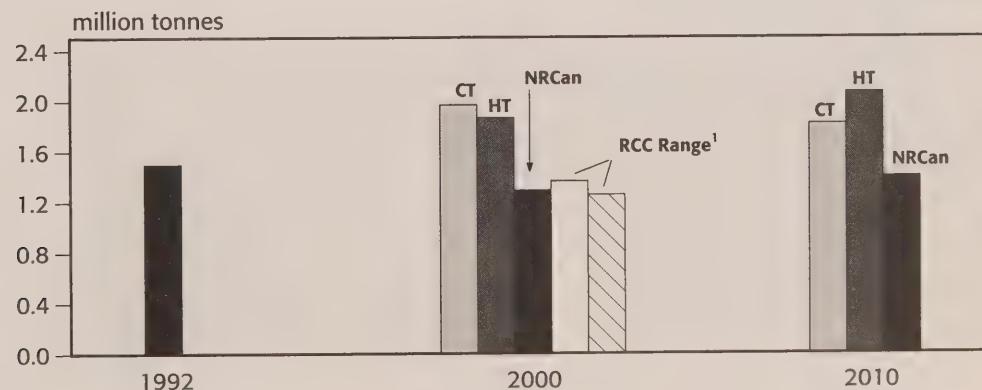
1 The range in *Canada's National Report on Climate Change* is based on the NRCan case. The range illustrates the effect of changing key variables affecting energy demand.

FIGURE 8-4 (a)
Nitrogen Oxides Emissions
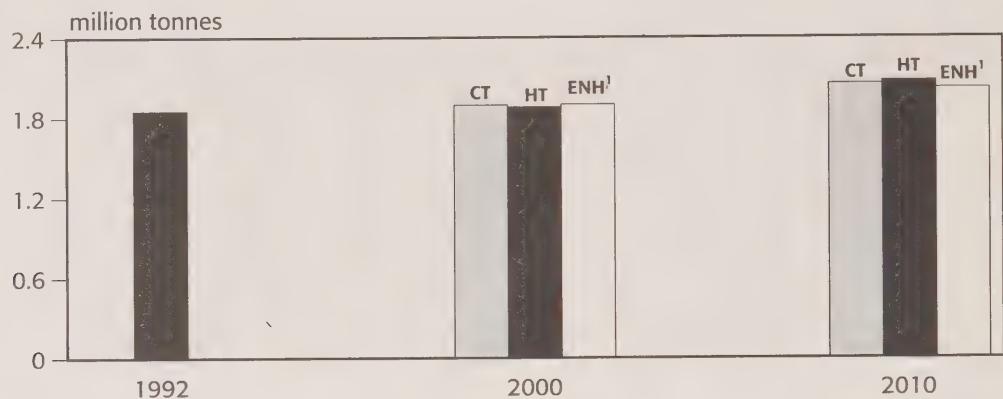
FIGURE 8-4 (b)
Volatile Organic Compounds Emissions
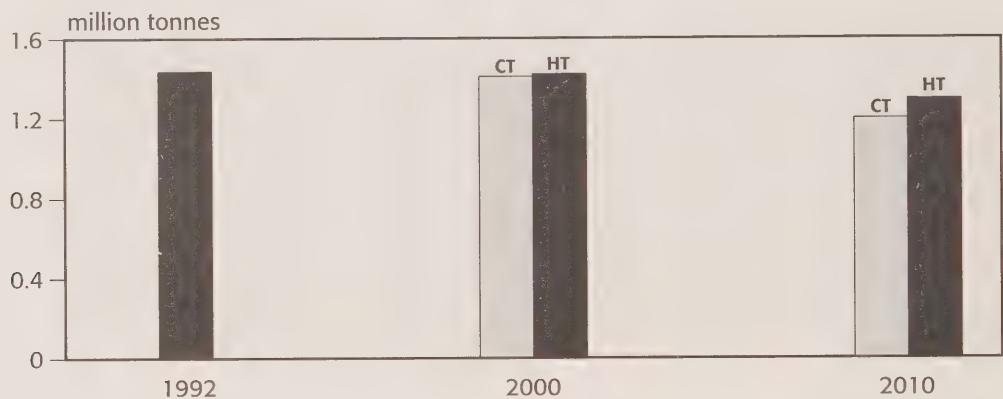
FIGURE 8-4 (c)
Sulphur Dioxide Emissions

1 Enhanced Cooperation in electricity

Chapter 9

SUMMARY AND CONCLUSIONS

In this analysis of the prospects for Canadian energy supply and demand we have focused on the implications of:

- different natural gas supply conditions on demand and supply of all energy sources;

- evolving oil supply technologies and different oil prices for Canadian oil supply;

- a more energy-intensive economy for energy demand; and

- more interprovincial planning of electricity supply together with open access to transmission facilities for the pattern of electricity generation and trade.

Our analysis resulted in substantially different natural gas price profiles in the two gas supply cases analyzed; by 2010 Alberta fieldgate prices are projected to average about $4.00 and $2.25 per gigajoule in real terms in the Current and High Tech cases respectively, compared to the 1993 level of $1.58. We adopted a reference oil price projection which implies small increases in the prices of refined petroleum products and we assumed that electricity prices would remain constant in real terms. Thus, over our study period the only substantial change in relative energy prices at the burner tip is an increase in natural gas prices relative to the prices of electricity and petroleum products in the Current Tech case. The costs and prices of alternative and renewable energy forms are, in general, high relative to conventional energy sources and we assumed they would remain so. We recognize that some alternative sources are now competitive in certain markets and, further, that technological progress may occur to enhance the commercial viability of alternative energy over our study period.

Growth in end use energy demand in all cases analyzed is higher than the rate of growth experienced in the 1980s for all major sectors. This is a result of a number of factors: projected increases in energy prices are moderate; in our view the adjustment of energy demand to the energy price increases of the late 1970s and early 1980s is largely complete; and, in our economic projections, growth in production is more concentrated in energy-intensive industries over our study period than it has been in the past 20 years.

Natural gas prices and the composition of economic growth have an important influence on end use energy demand. If relatively low gas prices are combined with an economic projection in which the output of energy-intensive industries grows relatively rapidly, end use demand is about one exajoule higher, or about ten percent, than if gas prices are higher and economic growth is less energy intensive. Moreover, natural gas demand increases much more rapidly in the High Tech case, in which gas prices increase relatively slowly, than in the Current Tech case.

The fuels used in electricity production and the geographical pattern of generating capacity are influenced substantially by the course of natural gas prices and the extent to which the provinces begin to jointly plan for electricity production and engage in more extensive, economically beneficial, interprovincial trade. In the Current and High Tech cases, which assume that planning continues to be done independently by provincial utilities, fossil fuel and hydro generation increase by similar amounts over the study period. In the case of fossil fuel generation the fuel selected depends importantly on fuel prices. For example, in the High Tech case, in which natural gas prices are relatively low, the amount of natural gas-fired generation is double what it is in the Current Tech case.

In a setting in which electricity generating capacity is planned on an interprovincial basis and access to transmission is available, our analysis suggests that large hydro projects in Labrador and Manitoba, which are too large to be developed for intraprovincial use, would be developed to supply regional loads. Hydro production from Labrador would be transmitted through Québec to the Atlantic provinces, Ontario and possibly the U.S. Hydropower from Manitoba would be transmitted to Ontario and Saskatchewan. In this case we estimate that the Labrador and Manitoba hydro projects would displace all new fossil-fired generating capacity from Newfoundland to Saskatchewan in the second half of the next decade at a unit cost about 75 percent that of the fossil fuel alternatives. Consequently, total fossil-fuelled generation in this case is somewhat lower by the end of the study period than in the Current and High Tech cases.

We analyzed the prospects for North American natural gas markets under a number of assumptions. The

two principal cases examined alternative assumptions concerning the nature and costs of gas supply:

- the conventional resource continues to comprise the bulk of production and is increasingly expensive to exploit (the Current Tech case); and

- new advances in technology and geological knowledge prevent the costs of finding and developing new gas reserves from rising appreciably from current levels (the High Tech case).

We also analyzed the implications of a higher U.S. gas demand profile and of the impact on North American gas markets of the introduction of supply from an additional, low cost, non-Canadian source such as Mexico.

Canadian exports of natural gas are highest in a high price, high U.S. demand world and lowest in a low price world with abundant North American supply. In all but one case analyzed the projected exports from Canada are generally at or above levels recently experienced. Exports decline somewhat in the case which combines the High Tech view with the assumption of an additional low cost North American supply source.

The combination of expanding exports and domestic demand leads, under all scenarios studied, to rapidly rising production of Canadian gas over the next two decades. Exports are the most important influence. Our analysis suggests that Canadian production could reach the neighbourhood of seven exajoules per year towards the end of our study period compared to 4.7 exajoules in 1993.

The implications of rising gas production for exploration and development activity depend importantly on the assumptions made about the impact of technological change. In the Current Tech case modest improvements in known technology continue: in that case our projection implies that gas-directed exploratory drilling would increase rapidly from its 1993 level of two million metres to about five million metres per year near the end of the study period. In the High Tech case, drilling and production technology change in unknown ways; it is, therefore, inherently impossible to generate estimates of activity levels without making additional assumptions about the impact of technological change.

The results of the analysis for the case in which U.S. demand increases very rapidly provide interested parties with a background for the Export Impact Assessment component of the Market-Based Procedure used by the Board to regulate long-term gas exports.

Our long-term analysis suggests that there is a wide range of plausible market outcomes for both gas price and volume. Different outcomes may have implications for short-term market adjustments which we have not completely analyzed. In this respect we note that there appeared to be agreement at the Export Impact Assessment Workshop that:

- the principal tools of long-term analysis provide limited understanding of adjustment processes; and

- more short-term analysis should be undertaken in order to understand adjustment processes better.

Canada's oil resource base is large and diverse, comprising conventional light and heavy oil in the WCSB, light oil in the frontier regions, and bitumen found in the oil sands in Alberta. Canadian oil supply has increased moderately in recent years as supply costs have declined due to industry rationalization and rapid technological progress. Among new technologies, horizontal drilling has had a particularly strong impact on oil supply. We assessed the prospects for Canadian oil supply under two assumptions about the progress of technology: a Current Tech assumption in which oil supply costs are related to technologies currently in use or which are close to becoming commercially viable, and a High Tech assumption which incorporates supply costs associated with technologies that are in the early stages of research. We also assessed the implications for oil supply of the upper and lower bounds of our sustainable range of oil prices (US$30 and US$15 per barrel, 1993 dollars).

Our analysis suggests that total Canadian crude oil production could increase over our study period so long as world oil prices are consistently above the mid-point of our sustainable range and/or technological progress further reduces supply costs. Any expansion in oil supply is likely to feature increases in heavy oil production, in bitumen production from the oil sands and light oil production from the frontiers. Light oil production from western Canada gradually declines over the study period. The state of resource depletion in the WCSB suggests that supply of western Canada conventional oil, particularly light crude oil, is unlikely to be sustained in the long run even under conditions of rapid technological progress. However, horizontal drilling and other new technologies may lead to a continued gradual increase in production in the near term and could delay the decline by several years.

The size and composition of the Canadian oil supply is very sensitive to oil prices between US$15 and

US$26. In a world in which oil prices track at the bottom of the sustainable range, total Canadian crude oil supply declines quite rapidly as no new supply sources are economically viable. In contrast, all sources are viable above US$26. Canada remains a net exporter of crude oil when oil prices are sustained at or above the mid-range level. At lower prices Canadian production declines sufficiently rapidly that Canada becomes a net importer towards the end of the study period.

Our projections, like those in the Climate Change Report, imply that, absent the implementation of specific control measures, emissions of the greenhouse gases of carbon dioxide and methane will continue to rise with growing use of fossil fuels over our study period.

Of the other gaseous emissions, those of nitrogen oxide rise moderately while energy-related emissions of volatile organic compounds and of sulphur dioxide decline over the study period. Emissions of carbon dioxide, nitrogen oxides and sulphur dioxide are lowest in the enhanced electricity trade case. In that case large amounts of fossil-fuelled electricity generation are displaced by hydro-electric generation.

There are wide ranges of possible and plausible outcomes for both energy demand and supply over the next two decades. Different outcomes result from variations in factors as diverse as economic activity, the pace of technological advance and, as in the case of electricity supply, the nature of trading and transmission arrangements. We do not present any one outcome as being more probable than another. Nor can it be said that, in general, any one outcome is more desirable than another.

The actual pattern of events will not be as smooth as suggested in our analysis. Markets will be required to adjust to changing circumstances and, as they do, fluctuations in volumes and prices can be expected to occur. We reiterate that our purpose has not been to engage in a detailed analysis or forecast of short-term developments; rather, it has been to shed some light on possible long-term trends.

GLOSSARY

Acid Rain

(Pluies acides) Sulphuric, nitric, organic, or other acids that acidify rain water.

Base Load Capacity

(Capacité de production de la charge de base) Electricity generating equipment which operates to supply the load over most hours of the year.

Biomass

(Biomasse) Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.

Bitumen

(Bitume) A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes, that has a viscosity greater than 10 000 millipascal-seconds (mPa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. Bitumen may contain sulphur and other non-hydrocarbon compounds and in its natural viscous state is typically not recoverable at a commercial rate through a well.

Blended Heavy Oil

(Pétrole lourd mélangé) Heavy crude oil to which light oil fractions have been added in order to reduce its viscosity to meet pipeline specifications.

Burner Tip Price

(Prix à la pointe du brûleur) The price paid by the end user for an energy commodity.

Capacity (electricity)

(Capacité [électricité]) The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.

Coal Bed Methane Gas

(Méthane des gisements de charbon) The naturally occurring, dry, predominantly methane, gas produced during the transformation of organic material into coal. It is present as molecules adsorbed within the molecular structure of all coals, as gas in matrix porosity, as free gas in open fractures in coal, and as gas dissolved in ground water within the coal.

Combined Cycle Generation

(Production d'électricité mixte) The simultaneous production of electricity using both combustion turbine and steam turbine generating units. Electricity is first produced by one or more combustion turbine/generator sets fuelled by either gas or light fuel oil. The hot exhaust gases from this process are then used to generate steam which, in turn, drives a steam turbine/generator to produce electricity.

Conventional Crude Oil	(*Pétrole brut classique*) Crude oil which at a particular point in time can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil. For the purpose of this report conventional crude oil is categorized as light or heavy crude oil, based mainly on the refining processes required to produce useful products. Our heavy crude oil category includes both heavy crudes and crudes which are classified by some others as medium.
Conventional Natural Gas	(*Gaz naturel classique*) Natural gas occurring in a normal porous and permeable reservoir rock which at a particular point in time can be technically and economically produced using normal production practices.
Crude Oil and Equivalent Hydrocarbons	(*Pétrole brut et hydrocarbures équivalents*) Sometimes referred to as "Crude Oil and Equivalent". Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.
Cumulative Production	(*Production cumulative*) The total amount of hydrocarbons produced to a given date.
Demand Side Management	(*Gestion de la demande*) Measures promoted by electric and natural gas utilities to favourably influence the amount and timing of customer energy demand.
Discovered Recoverable Resources	(*Ressources découvertes et récupérables*) Resources which are estimated at this time to be recoverable from known accumulations (i.e., accumulations which have been shown to exist by drilling, testing or production) using known technology. They include cumulative production, remaining reserves and "other discovered recoverable resources".
Efficiency of Fuel (or Burner Tip Efficiency)	(*Rendement du combustible [ou rendement à la pointe du brûleur]*) The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.
Electricity Production	(*Production d'électricité*) The amount of electric energy expressed in kilowatt hours or multiples of kilowatt hours produced in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load), the availability of fuels, the cost of fuels, stream flows and reservoir water levels, and environmental constraints.
Emission Factor	(*Facteur d'émission*) An estimate of the rate at which a substance is released to the atmosphere as a result of some activity (e.g., kilograms of sulphur dioxide emitted per tonne of coal burned).

End Use Demand for Energy (or Secondary Energy Demand) — *(Demande d'énergie pour utilisation finale [ou demande d'énergie secondaire])* Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.

Energy Intensity — *(Intensité énergétique)* In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is the average fuel economy of the car stock. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of real GDP.

Established Reserves (Oil and Gas) — *(Réserves établies [pétrole et gaz naturel])* Those reserves recoverable under current technology and present and anticipated economic conditions, specifically those proved by drilling, testing or production ("proved reserves"), plus that judgement portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty ("probable reserves"). Established reserves are typically comprised of proved reserves plus one-half probable reserves.

Federal Energy Regulatory Commission — The FERC is responsible for the regulation of all interstate trade in natural gas in the U.S. It regulates the tolls and tariffs of interstate oil and natural gas pipelines and approves the construction of new facilities. It also regulates the transmission and wholesale sale of electricity in interstate commerce, licenses non-federal hydroelectric projects, and oversees related environmental matters.

Feedstock — *(Charge d'alimentation)* Raw material supplied to a refinery or petrochemical plant.

Fieldgate Price (gas) — *(Prix après traitement [gaz naturel])* The price received by producers for natural gas delivered to a pipeline system (e.g., NOVA's pipeline system for Alberta).

Frontier Areas — *(Régions pionnières)* Generally, the northern and offshore areas of Canada.

Fuel Switching Capability — *(Capacité d'utilisation d'un combustible de remplacement)* A customer's ability to use two or more fuels.

Gas-in-place — *(Gaz en place)* see In Place Resources

Greenhouse Effect — *(Effet de serre)* A naturally occurring phenomenon in the earth's atmosphere in which incoming solar short-wave radiation passes relatively unimpeded, but long-wave radiation emitted from the warm surface of the earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperature. The greenhouse effect is enhanced by the addition to the atmosphere of several trace gases. This phenomenon is analogous to the way in which heat is trapped by the glass in a greenhouse.

Heavy Crude Oil

(Pétrole brut lourd) A term applied to crude oil having a high density; also a collective term used to refer to conventional heavy crude oil and bitumen. In this report, heavy crude oil supply and demand numbers include heavy crude oil as well as any light fractions added to reduce viscosity to facilitate pipeline transportation but exclude any conventional heavy crude oil or bitumen upgraded to light crude oil.

Heavy Fuel Oil

(Mazout lourd) In this report, includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).

Horizontal Well

(Puits horizontal) A well which deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.

Hydroelectric Generation

(Production hydro-électrique) Electricity produced by an electric generator driven by a hydraulic turbine.

In Place Resources

(Ressources en place) The gross volume of crude oil, natural gas and related substances estimated at a particular point in time to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.

In Situ Recovery

(Récupération en place) The process of recovering crude bitumen from oil sands other than by surface mining.

Independent Power Producers

(Producteurs d'électricité indépendants) Electric power facilities built by private investors to serve load requirements of a utility or of an industry.

Initial Reserves

(Réserves initiales) Initial reserves is a term often used to refer to reserves prior to deduction of any production. Alternatively, initial reserves can be described as the sum of remaining reserves and cumulative production at the time of the estimate.

Integrated Mining Plant

(Exploitation minière intégrée) A mining and upgrading operation where oil sand is mined from open pits and separated into sand and bitumen. The bitumen is then upgraded into synthetic light crude oil by a refining process.

Integrated Resource Planning

(Planification intégrée des ressources) A process used to identify the appropriate mix of all known resources that will minimize the cost and risk associated with providing energy services to society over the long run. Resources include traditional supply sources, as well as energy conservation and management of peak demand.

Light Crude Oil

(Pétrole brut léger) A term applied to crude oil having a low density; also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil, synthetic crude oil and pentanes plus. In this report, light crude oil supply and demand numbers exclude any light crude fractions added to heavy crude oil.

Light Fuel Oil	*(Mazout léger)* Furnace fuel oil (No. 2 fuel oil).
Natural Gas Liquids	*(Liquides de gaz naturel)* Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, pentanes plus and condensate and may include small quantities of non-hydrocarbons.
Nitrogen Oxides	*(Oxydes d'azote)* The primary nitrogen by-products of combustion are nitrogen oxide (NO) and nitric dioxide (NO_2)which are collectively known as nitrogen oxides (NO_X). Nitrogen oxides contribute to the formation of acid rain and are important in the production of ozone in the lower atmosphere.
Nitrous Oxide	*(Oxyde nitreux)* A chemically active trace gas which has a large number of natural sources and is a secondary product of combustion. Nitrous oxide is a strong greenhouse gas.
Non-Utility Generation	*(Production par une société autre qu'un service public)* Electric power facilities built, owned and operated by specific industries or private investors to serve the industry's own electricity needs or to serve the electric utility load requirement.
Oil Sands	*(Sables pétrolifères ou sables bitumineux)* Deposits of sand or sandstone, or other sedimentary rocks containing bitumen.
Oil-in-place	*(Pétrole en place)* See "In Place Resources".
Open Access	*(Libre-accès)* The non-discriminatory access to pipelines or electricity transmission lines.
Other Discovered Recoverable Resources	*(Autres ressources découvertes et récupérables)* Those discovered resources that are estimated at this time to be recoverable using known technology but that have not yet been recognized as established reserves because of uncertain economic viability.
Peaking Capacity	*(Capacité de pointe)* Electricity generating equipment which is available to meet peak demand.
Pentanes Plus	*(Pentanes plus)* A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate or crude oil. For the purpose of this report pentanes plus includes condensate.
Permeability	*(Perméabilité)* A measure of the capacity of a reservoir rock to transmit a fluid (liquid or gas).
Petroleum	*(Pétrole)* A naturally occurring mixture of predominantly hydrocarbons in the gaseous, liquid or solid phase.

Photovoltaics

(Dispositif photovoltaïque) Photovoltaic systems produce direct-current electric power from solar energy, using semiconductor materials.

Potential Economic Growth

(Croissance économique potentielle) Represents the upper bound to growth for a given unemployment rate; however, growth could exceed potential for a period of time if there are underutilized resources (e.g., if the unemployment rate at the beginning of the period were higher than the given rate). Potential growth is approximately equal to the sum of the growth rates of the labour force, capital stock and productivity.

Primary Energy Demand

(Demande d'énergie primaire) Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g., coal to electricity), and energy used by suppliers in providing energy to the market (e.g., pipeline fuel).

Primary Recovery

(Récupération primaire) See "Recovery – Primary".

Productive Capacity

(Capacité de production) The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to plant turnarounds and operational problems. Productive capacity is referred to by the ERCB as "Available Supply".

Recovery – Improved

(Récupération assistée) The extraction of additional crude oil, natural gas and related substances from reservoirs through a production process other than natural depletion. Improved recovery includes both secondary and tertiary recovery processes, such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding and the use of miscible and immiscible displacement fluids.

Recovery – Primary

(Récupération primaire) The extraction of crude oil, natural gas and related substances from reservoirs utilizing only the natural energy available in the reservoirs.

Recovery – Enhanced

(Récupération assistée) A term frequently used in Canada which is equivalent to improved recovery.

Remaining Reserves

(Réserves restantes) Initial reserves less cumulative production at the time of the estimate.

Reserves Additions

(Additions aux réserves) Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserve estimates for established pools.

**Reserves Life Index or
Reserves to Production Ratio**

(Indice de durée des réserves ou Ratio réserves/production)
Remaining reserves divided by annual production.

Reservoir

(Gisement) A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil, natural gas and related substances that is confined by impermeable rock or water barriers, and is individual and separate from other reservoirs.

Solar Energy – Active System

(Énergie solaire – système actif) Solar energy collection system which transfers heat captured from solar radiation through mechanical devices.

Solar Energy – Passive System

(Énergie solaire – système passif) Solar energy collection system which captures solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.

Spot Price

(Prix sur le marché du disponible) Generally, the price applicable to a sale of gas under a 30-day contract or less.

Stand Alone Upgrader

(Usine de valorisation indépendante) An upgrading facility that is not associated with a mining plant or a refinery.

Sulphur Dioxide

(Dioxyde de soufre) Refers to gaseous sulphur dioxide (SO_2). In some cases, emissions may contain small amounts of sulphur trioxide (SO_3) and sulphurous and sulphuric acid vapour. Excludes particulate or aerosol sulphate.

Supply Cost

(Coût des approvisionnements) Gas or oil supply costs express some or all costs associated with resource exploitation as an average cost per unit of production over the project life. The main cost components are: capital costs associated with exploration (geological and geophysical surveys and exploration drilling), development (development drilling and surface facilities), production operating costs, federal and provincial taxes, resource royalties and the threshold rate of return.

Synthetic Crude Oil

(Pétrole brut synthétique) A mixture of hydrocarbons similar to crude oil derived by upgrading crude bitumen from oil sands, kerogen from oil shales, or other substances such as coal. It may contain sulphur or other non-hydrocarbon compounds.

**Three-Dimensional Seismic Survey
(3-D Seismic)**

(Étude sismique tridimensionnelle) The gathering of seismic data in a closely spaced grid, from a prospective hydrocarbon area, using artificially created sound waves. This data is then enhanced through computer processing to display the spatial relationships of the geological formations in three dimensions, in contrast to the conventional display in two-dimensional cross-sections along the line of survey.

Tight Gas

(Gaz d'une formation imperméable) Natural gas contained in low permeability reservoirs.

Ultimate Recoverable Resource Potential

(Potentiel ultime de ressources récupérables) An estimate, at a given point in time, of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, other discovered resources and undiscovered recoverable resources.

Unconventional Crude Oil

(Pétrole brut non classique) Crude oil which is not classified as conventional crude oil. An example of unconventional crude oil would be bitumen.

Unconventional Natural Gas

(Gaz naturel non classique) Natural gas which is not classified as conventional natural gas. An example of unconventional natural gas would be coal bed methane.

Undiscovered Recoverable Resources

(Ressources récupérables pas encore découvertes) Resources that are estimated at this time to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but which have not yet been shown to exist by drilling, testing or production.

Upgrading

(Valorisation) The processing of bitumen or heavy crude oil into a synthetic crude oil.

Viscosity

(Viscosité) The measure of the resistance of a fluid to flow.

Volatile Organic Compounds

(Composés organiques volatils) Includes only photochemically reactive hydrocarbons. Excludes methane, ethane and chlorinated organics.

Wood Waste

(Résidus de bois) Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Canada

CANADIAN ENERGY

Supply and Demand 1993 - 2010

TECHNICAL REPORT

NATIONAL ENERGY BOARD

CONVERSION FACTORS – METRIC TO IMPERIAL UNITS[1]

metre (m)	=	3.28 feet
cubic metre (m³) of oil	=	6.3 barrels
cubic metre (m³) of natural gas	=	35.3 cubic feet
litre (L)	=	0.22 Imperial gallon
gigajoule (GJ)	=	950.0 cubic feet of natural gas at 1 000 Btu per cubic foot, or 0.16 barrels of oil, or 0.28 megawatt hours of electricity
tonne (t)	=	2 200 pounds

ABBREVIATIONS

gigajoule (GJ)	=	10^9 Joules (J)
terajoule (TJ)	=	10^{12} J
petajoule (PJ)	=	10^{15} J
exajoule (EJ)	=	10^{18} J
kilowatt (kW)	=	10^3 watts
megawatt (MW)	=	10^3 kilowatts
megawatt hour (MW.h)	=	10^3 kilowatt hours (kW.h)
gigawatt hour (GW.h)	=	10^6 kW.h
terawatt hour (TW.h)	=	10^9 kW.h

1   Approximate conversion factors

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ABBREVIATIONS OF NAMES AND TERMS

AAGR	Average Annual Growth Rate
AAPG	American Association of Petroleum Geologists
Act	the National Energy Board Act
ALCAN	Aluminum Company of Canada Ltd.
Alt Macro	Alternative Macroeconomic assumption
AMP	(Alberta) Average Market Price
ANG	Alberta Natural Gas Company
ATF	Aviation Turbine Fuel
BC Hydro	British Columbia Hydro and Power Authority
(the) Board or NEB	(the) National Energy Board
CAPP	Canadian Association of Petroleum Producers
CEC	California Energy Commission
CFC	Chlorinated Fluorocarbons
CGA	Canadian Gas Association
CNOPB	Canada-Newfoundland Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
COGLA	Canada Oil and Gas Lands Administration
Current Tech (or CT)	Current Technology case
DFI	Decision Focus Incorporated
DFO	Diesel Fuel Oil
DOE	Department of Energy (U.S.)
DRI	Data Resources Incorporated
DSM	Demand Side Management
EAF	Electric Arc Furnace
ECAR	East Central Area Reliability Coordination Agreement (a NERC Region)
EDM	Energy Demand Model
EIA	Export Impact Assessment or Energy Information Administration (U.S.)
ENC	U.S. East North Central Region
ENRON	Enron Corporation
ERCB	Energy Resources Conservation Board (Alberta)
EUPC	Electric Utility Planning Council (Alberta)
FERC	Federal Energy Regulatory Commission (U.S.)
FOBT	Free on board, trimmed
Foothills	Foothills Pipe Lines (Yukon) Ltd.
FSU	Former Soviet Union

FTA	Free Trade Agreement
GAD	Gross air dried
GAR	Gross as received
GATT	General Agreement on Tariffs and Trade
GDP	Gross Domestic Product
GEA	Geological Exploration Associates
GHG	Greenhouse Gas(es)
GRI	Gas Research Institute
GWP	Global Warming Potential
HFO	Heavy fuel oil
High Tech (or HT)	High Technology case
IEA	International Energy Agency
IGCC	Integrated (Coal) Gasification Combined Cycle
Informetrica	Informetrica Limited
IPL or Interprovincial	Interprovincial Pipe Line Company
IPP	Independent Power Producer
IRP	Integrated Resource Planning
LDC	Local Distribution Company
LFO	Light fuel oil
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MAPP	Mid-Continent Area Power Pool (a NERC Region)
MBP	Market-Based Procedure
MECL	Maritime Electric Co. Ltd. (Prince Edward Island)
MMS	Minerals Management Service (U.S.)
Mogas	Motor Gasoline
NAFTA	North American Free Trade Agreement
NARG	North American Regional Gas Model
NB Power	New Brunswick Electric Power Corporation
NEPOOL	New England Power Pool (U.S. power pool area)
NERC	North American Electric Reliability Council
NGL	Natural Gas Liquids
NGMA	Natural Gas Market Assessment
NGV	Natural Gas Vehicles
N&LH	Newfoundland and Labrador Hydro
NOVA	NOVA Corporation of Alberta
NPC	National Petroleum Council (U.S.)

NRCAN	Natural Resources Canada
NSPI	Nova Scotia Power Incorporated
NUG	Non-Utility Generator (electricity)
NYPP	New York Power Pool (U.S. power pool area)
OECD	Organization for Economic Cooporation and Development
OPEC	Organization of Petroleum Exporting Countries
PCI	Pulverized Coal Injection
PEL	Petroleum Economics Limited
PGC	Potential Gas Committee (U.S.)
PGT	Pacific Gas Transmission Company
PNW	U.S. Pacific Northwest
POWEREX	British Columbia Power Exchange Corporation
RDP	Real Domestic Product
RR/P	Remaining reserves to production ratio
RTG	Regional Transmission Group
SaskPower	Saskatchewan Power Corporation
Sproule	Sproule Associates Limited
TCPL or TransCanada	TransCanada PipeLines Limited
Trans Mountain (or TMPL)	Trans Mountain Pipe Line Company Ltd.
U.S.	United States
USGS	United States Geological Survey
VOC	Volatile Organic Compounds
WCSB	Western Canada Sedimentary Basin
WEFA	Wharton Econometric Forecasting Associates
WSCC	Western Systems Coordinating Council (NERC Region)
WTI	West Texas Intermediate crude oil
1986 Report	*National Energy Board, Canadian Energy Supply and Demand 1985-2005*, Summary and detailed reports, October, 1986
1988 Report	*National Energy Board, Canadian Energy Supply and Demand 1987-2005*, Summary and detailed reports, September, 1988
1991 Report	*National Energy Board, Canadian Energy Supply and Demand 1990-2010*, Summary and detailed reports, June 1991

UNITS

Prefix	Multiple	Symbol
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

GJ	gigajoule	=	10^9 Joules(J)
TJ	terajoule	=	10^{12} J
PJ	petajoule	=	10^{15} J
EJ	exajoule	=	10^{18} J

kW	kilowatt	=	10^3 Watts
kW.h	kilowatt hour	=	10^3 W.h
MW	megawatt	=	10^3 kW
MW.h	megawatt hour	=	10^3 kW.h
GW	gigawatt	=	10^6 kW
GW.h	gigawatt hour	=	10^6 kW.h
TW	terawatt	=	10^9 kW
TW.h	terawatt hour	=	10^9 kW.h

m^3	=	cubic metre
L	=	litre
kPa	=	kilopascal (pressure)
kg/m^3	=	kilograms per cubic metre (density)

t	=	tonne
kt	=	kilotonne
Mt	=	megatonne

°API	=	degrees gravity on American Petroleum Institute scale (See Glossary)
Btu	=	British thermal unit
psia	=	pounds per square inch absolute
ppmv	=	parts per million by volume

Mcf	=	thousand cubic feet
Bcf	=	billion cubic feet
Tcf	=	trillion cubic feet

bbl	=	barrel
MMbd	=	million barrels per day

C$ or $	=	Canadian dollars
US$	=	United States dollars

CONVERSION FACTORS – METRIC UNITS TO IMPERIAL UNITS

Metric Units   **Imperial Equivalent Units**

1 cubic metre of oil

    (15°C and 922 kg/m³)   = 6.292 26 barrels (60°F and 22°API) for conventional heavy crude oil

    (15°C and 855 kg/m³)   = 6.292 58 barrels (60°F and 34°API) for conventional light crude oil

    (15°C and 739 kg/m³)   = 6.294 03 barrels (equilibrium pressure, 60°F and 60°API) for pentanes
plus

1 cubic metre of natural gas   = 35.301 01 cubic feet (14.73 psia and 60°F)
(101.325 kilopascals and 15°C)

1 cubic metre of ethane (liquid)   = 6.330 barrels of ethane (equilibrium pressure and 60°F)
(equilibrium pressure and 15°C)

                                                = 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)

1 cubic metre of propane (liquid)   = 6.300 barrels of propane (equilibrium pressure and 60°F)
(equilibrium pressure and 15°C)

1 cubic metre of butanes (liquid)   = 6.297 barrels of butanes (equilibrium pressure and 60°F)
(equilibrium pressure and 15°C)

1 tonne   = 1.102 311 short tons

1 kilojoule   = 0.948 213 3 British thermal units (Btu)

1 gigajoule (GJ)   = approximately   0.95 million Btu, or
                                            0.95 thousand cubic feet of natural gas
                                            at 1 000 Btu per cubic foot

1 petajoule (PJ)   = approximately   0.95 billion cubic feet of natural gas, or
                                            165 000 barrels of oil, or
                                            0.28 terawatt hours of electricity

1 litre (L)   = approximately .22 Imperial gallon

1 kilogram (kg)   = approximately 2.2 pounds

1 metre (m)   = approximately 3.28 feet

GROSS ENERGY CONTENT FACTORS

Natural Gas   37.23 MJ/m³ [1]

Ethane (liquid)   18.36 GJ/m³

Propane (liquid)   25.53 GJ/m³

Butanes (liquid)   28.62 GJ/m³

Crude Oil   - Light   38.51 GJ/m³
                   - Heavy   40.90 GJ/m³
                   - Pentanes Plus   35.17 GJ/m³

Coal   - Anthracite   27.70 GJ/tonne
                   - Bituminous   27.60 GJ/tonne
                   - Subbituminous   18.80 GJ/tonne
                   - Lignite   14.40 GJ/tonne
                   - Average domestic use   22.20 GJ/tonne

Petroleum Products - Aviation Gasoline   33.52 GJ/m³
                   - Motor Gasoline   34.66 GJ/m³
                   - Petrochemical
                     Feedstocks   35.17 GJ/m³
                   - Naphtha Specialties   35.17 GJ/m³
                   - Aviation Turbo Fuel   35.93 GJ/m³
                   - Kerosene   37.68 GJ/m³
                   - Diesel   38.68 GJ/m³
                   - Light Fuel Oil   38.68 GJ/m³
                   - Lubes and Greases   39.16 GJ/m³
                   - Heavy Fuel Oil   41.73 GJ/m³
                   - Still Gas   41.73 GJ/m³
                   - Asphalt   44.46 GJ/m³
                   - Petroleum Coke   42.38 GJ/m³
                   - Other Products   39.82 GJ/m³

Electricity
   Secondary   3.6 MJ/kW.h
   Primary   - Hydro   3.6 MJ/kW.h
                   - Nuclear   12.1 MJ/kW.h [2]

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1   Assumes 15°C, 101.325 kPa and free of water vapour. The energy content of 37.23 MJ/m³ is approximately the equivalent of 1 000 Btu per cubic foot
    in the Imperial system. The actual energy content will vary depending on the amount of natural gas liquids (mostly ethane) contained in the gas.

2   Typical value. Actual values at nuclear generating plants depend on specific plant efficiencies.

FOREWORD

The National Energy Board ("NEB" or "the Board") was created by an Act of Parliament in 1959. The Board's regulatory powers under the *National Energy Board Act* ("the Act") include the authorizing of the export of oil, gas and electricity, of the construction of interprovincial and international oil and gas pipelines and international power lines, the setting of just and reasonable tolls for pipelines under federal jurisdiction and the regulation of oil and gas activities on Canada lands in the north. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception, the Board has prepared and maintained projections of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. In a July 1987 decision in which the Board adopted the Market-Based Procedure ("MBP") for regulating natural gas exports, the Board indicated its intention to continue to produce and publish these *Canadian Energy Supply and Demand* reports as one component of the ongoing monitoring part of the MBP. The latest of these reports was issued in the fall of 1991.

The objectives of this report are:

- to provide a comprehensive "all energy" market analysis and outlook to serve as a standard of reference for all parties interested in Canadian energy issues;

- to provide a framework for public discussion on emerging energy issues of national importance; and

- to monitor the prospects for the supply, demand and price of natural gas in Canada pursuant to the MBP.

In conducting its analysis the Board, or Board staff, has always obtained the views of interested parties. Over the years a number of changes have been made to the process of obtaining external views. In the reports of the late 1970s and early 1980s external views were gathered by submissions requested by the Board which were sometimes the subject of examination in public hearings. Starting with the 1984 report, submissions were no longer subject to public examination; in subsequent reports, information was gathered from interested parties on a more informal basis.

In this version of *Canadian Energy Supply and Demand*, Board staff continued to use an informal consultation process involving two rounds of discussions. The initial round was conducted at an early, formative, stage of the analysis. It involved dialogue about issues, the appropriate analytical approach and report format. A brief report on these consultations, and on the actions that resulted from them, was made available to interested parties in July 1993. A second round of consultations, to discuss preliminary results, was held in December 1993. Important differences between the views expressed by consultees and the Board's analysis are noted and discussed in the report. In addition Board staff engaged in extensive consultations with many sectors of the energy community. We greatly appreciate the advice we received and the interchange of views during our consultations and we thank those who contributed their time and expertise.

These reports are issued by the Board for the information of the public. A number of parties have raised concerns over the use of *Canadian Energy Supply and Demand* reports in the Board's regulatory proceedings, and questioned whether these reports are an official reflection of Board views. The Board therefore wishes to clarify its views in this regard.

The Board recognizes that parties have not had the opportunity to examine or test the findings and conclusions contained in these reports in a public forum. Material from them may be used as part of the evidentiary record in particular regulatory proceedings to the extent that any party chooses to rely on such material, just as it could rely on any public document. In such a case, the material in effect is adopted by the party introducing it. In this respect, there has been no change in the way in which the report is used by the Board.

This technical report and the statistical appendix provide analytical detail and supporting information for the Board's current version of *Canadian Energy Supply and Demand*. A companion report, entitled *Canadian Energy Supply and Demand 1993-2010, Trends and Issues*, was released in July 1994.

Chapter 1

INTRODUCTION

Since its inception the National Energy Board has published assessments of the long-term outlook for energy in Canada. The Board has always recognized that there is considerable uncertainty about the future evolution of energy markets stemming from both demand and supply behaviour. Over a period as long as twenty years fundamental changes can be expected to affect society, the economy, and government policies, all of which can profoundly influence the evolution of energy markets. For purposes of long-term analysis a single estimate of the most likely course of energy supply and demand is not particularly useful or suitable. In fact, the Board has explicitly stated in recent reports that its analysis is not intended to provide a "forecast" but, rather, to give a broad assessment of the implications of possible variations in key underlying variables, such as world oil prices, for the long-run energy outlook. This report continues that tradition.

Further, the analysis in this report pertains to long-run trends in energy markets; it does not purport or attempt to assess year-to-year fluctuations in the demand for and supply of energy or in energy prices. Fluctuations will occur on a monthly, annual and multi-year basis, as recent experience demonstrates, but they are not necessarily indicative of longer run trends. We do not attempt to analyze the prospects for the emergence of surpluses of commodities such as natural gas or of shortages as reflected in short-term price spikes. In reasonably well functioning markets sustained surpluses or "shortages" will not occur. There can, of course, be difficulties associated with supply/demand imbalances and sharp changes in price but these are short run and transitory in nature; they are not a continuing characteristic of markets over long periods of time.[1]

The response of markets, in Canada and elsewhere, to the oil price shocks of the 1970s and, more recently, to changing circumstances in North American natural gas markets, is strong evidence of the validity of this view. Over long periods of time such as the period considered in this report, the trends in energy supply, demand and prices will reflect the influence of changes in the fundamentals of technology, consumer and producer behaviour and government policies.

It is also important to note that our analysis is restricted in that we do not speculate on the future course of government policies, including energy and environmental policies. Rather we conduct an analysis of plausible trends in energy market variables within the currently existing policy framework. For example, although this report analyzes the implications of energy supply and demand trends for levels of greenhouse gas emissions, we do not develop and analyze possible government policies to achieve greenhouse gas emissions targets. There is also much public discussion of the prospects for policy initiatives related to increased use of alternative and renewable forms of energy. In fact, it is frequently stated that such new energy forms can only be viable with changes to government policies. We assess the prospects for such energy forms based on their current and prospective costs and the prices of competing fuels. While we conclude that they are not generally commercially viable with present policies, we do not assume policy changes and therefore we do not project increased use.

We have, in recent years, canvassed readers of these reports as to their usefulness and as to the appropriate structure and framework of analysis. Two opinions have been strongly expressed:

- the reports should emphasize the key uncertainties related to the future course of energy supply and demand and the implications of such uncertainties; and

- notwithstanding the importance of analyzing these implications, it is important to have an integrated and consistent quantitative analysis, which includes all energy commodities, supporting observations and conclusions and the Board should have a view about the most likely evolution of energy markets.

These views have led us to change the format and the manner of presenting the results of the analysis. In order to respond to a diverse readership two reports have

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1   This does not mean that these transitory phenomena are unimportant; rather, it is to say that they are best addressed by other kinds of analysis. Two recent examples of short-run analysis of natural gas markets are: National Energy Board, *Natural Gas Market Assessment, Canadian Natural Gas Market Mechanisms: Recent Experiences and Developments*, November 1993 and National Energy Board, *Natural Gas Market Assessment, Natural Gas Supply Western Canada, Recent Developments (1982-1992), Short-Term Deliverability Outlook (1993-1996)*, November 1993.

been published. The first report, *Canadian Energy Supply and Demand 1993-2010, Trends and Issues*, July 1994, focused on the broad outlines of prospective energy market developments under different underlying assumptions about the values of key variables. The results were presented as a range of possible outcomes. This technical report provides detailed descriptions of the analytical methods used and the quantitative results. The quantitative analysis will be of value to users who wish to develop their own views of prospects or to have a detailed assessment of the impact of alternative assumptions. Neither report purports to contain a "forecast" of energy market developments.

FRAMEWORK OF ANALYSIS

In each of its energy outlook reports issued in recent years, the Board has analyzed the implications for the Canadian energy market of different assumptions about the future course of key variables. In reports issued before 1991, the emphasis was on the implications of alternative profiles of world oil prices and economic growth. In 1991 the analysis was expanded, in view of interest in the prospects for natural gas markets, to incorporate a broader assessment of the implications of alternative estimates of potential natural gas resources. It also provided, for the first time, estimates of levels of greenhouse gas emissions arising from the supply and demand projections. In determining the analysis to be conducted for this report we decided:

- not to repeat earlier analysis where, in our view, it remains valid; and

- to concentrate our efforts on areas of greatest interest which are also relevant to the work of the Board.

Accordingly, this report focuses on assessing the implications of alternative assumptions about technological progress as they affect the costs of supplying natural gas in the future. It also continues to provide assessments of the implications of new and ongoing uncertainties which are particularly important for energy demand and for the supply of specific energy forms. For natural gas, the recent emergence of a close balance between demand and supply in an increasingly integrated North American gas market, following a prolonged period of excess productive capacity, has led to renewed interest and concern about the prospects for natural gas prices. There is also emerging interest in the impact of technological progress on the cost of finding and producing incremental natural gas reserves.

The issues of the price and supply cost of natural gas were frequently raised and discussed during consultations we conducted in the course of preparing this report. They were also main topics of interest during the review conducted by the Board in 1993 of the Export Impact Assessment[2] component of the procedure used by the Board in the regulation of long-term natural gas exports. These matters were also the focus of a comprehensive study by the U.S. National Petroleum Council on the outlook for North American supply and demand of natural gas[3].

A major part of the analytical effort therefore focused on the development of two cases differentiated by alternative views about the impact of technological change on the costs of finding, developing and producing natural gas. Other assumptions, such as those regarding the future course of oil prices, economic growth, and energy transportation costs, are common to the two cases. The potential impacts of different oil prices, economic growth and other factors are examined in sector-specific analysis. A summary of the framework of analysis appears in Table 1-1.

The Current Gas Supply Technology ("Current Tech") case assumes that existing technologies related to the finding and production of natural gas will evolve during our study period, resulting in some moderation in the rate of increase in gas supply costs through time but that no new technologies are developed. Natural gas supply costs rise with increasing production as new fields are explored and developed. This assumption is similar to the approach used in past Board reports, and is the traditional approach to natural gas supply analysis.

The High Gas Supply Technology ("High Tech") case, on the other hand, assumes that continued technological advances will, to a large extent, offset increases in the costs of gas supply even as new reserves are found and produced. This concept is consistent with the general observation that most mineral commodities have exhibited flat or declining supply costs throughout the extensive historical periods of their exploitation. This approach generates a considerably flatter profile for future supply costs compared to the Current Tech case. In other words, industry supply costs are substantially lower in the High Tech case, which, other things equal, imply lower market prices for gas than in the Current Tech case.

2   National Energy Board, *Export Impact Assessment Workshop, A Summary of Discussion*, 1 April 1993.

3   National Petroleum Council, *The Potential for Natural Gas in the United States*, December 1992.

The differences in natural gas supply costs between the two cases (and the resulting differences in field and end use prices), lead to appreciable variations in North American energy demand, fuel shares by end users, Canadian gas export levels and fuel choices by electric utilities.

Following the Export Impact Assessment Workshop conducted in April, 1993 the Board decided to integrate its analysis of the long-run impact of incremental natural gas exports with analysis conducted for this report[4]. To fulfill this commitment we include an analysis of the impact on Canadian gas markets of a substantial increase in U.S. demand for natural gas relative to the two cases described above.

Further, there is increasing interest in the implications for Canada of potential natural gas imports into the U.S. from Mexico or from other new sources of low cost gas supplies. We have, therefore, analyzed the implications for North American natural gas markets, and specifically for Canadian exports, of the introduction into the North American market of a new, low-cost, source of supply.

Turning to oil, world oil markets have been characterized in recent years by a tendency for prices to drift downward and for expectations about future prices to be lower than previously held views. Thus controlling the costs of finding and producing oil from Canada's relatively high cost conventional and oil sands resources has become critical to the success of the Canadian upstream oil industry. At the same time there have been a number of technological developments in oil production which have tended to reduce the costs of producing those resources. Such developments include

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4 National Energy Board, Export Impact Assessment, letter to Interested Parties, 26 August 1993.

TABLE 1-1
Framework of Analysis[1]

Issues	Scope
Two Main Cases	
1. Current Gas Supply Technology ("Current Tech") – supply costs increase as new reserves are found and developed	Comprehensive for all supply sectors and energy demand
2. High Gas Supply Technology ("High Tech") – supply cost increases are mitigated by technological change	Comprehensive for all supply sectors and energy demand. Includes a high technology assumption for oil supply.
Extended Analysis	
3. More energy-intensive economy ("Alternative Macro")	Energy demand
4. Enhanced inter-utility cooperation ("Enhanced Cooperation")	Electricity supply
5. Export Impact Assessment – higher U.S. gas demand	Natural gas supply, demand and prices
6. Additional low-cost gas supply	Natural gas supply, demand and prices
7. High and low oil prices (US$30 and US$15 per barrel)	Oil supply

1 Unless indicated otherwise prices and costs are expressed in constant 1993 Canadian dollars.

horizontal, multiple-leg wells and a number of technologies aimed at reducing the costs and improving the recovery of oil in place, particularly heavy oil resources. Recognizing that the impacts of these emerging technologies are relatively speculative at this time, we have assessed the implications for Canadian oil supplies of alternative rates of development and use of such technologies. We have also analyzed the implications for Canadian oil supply of relatively low and high future oil price tracks.

For electricity, there is increasing interest in the prospects for enhanced cooperation and trade across traditional utility franchise areas in both Canada and the U.S. The potential benefits from such cooperation and trade were analyzed by the Board pursuant to a request from the Minister of Energy, Mines and Resources in a report which has recently been released by the Minister[5]. We have pursued this analysis by assessing the implications of enhanced inter-utility trade for the nature and geographical distribution of generating capacity and related atmospheric emissions.

The demand for energy is strongly influenced by the structure of economic activity, in particular by the share of economic activity accounted for by the production of energy-intensive commodities relative to less energy-intensive goods and services. Over the past two decades the production of services has been rising relative to the production of goods in Canada as in other industrial countries. However, it is far from clear that this trend will continue. In fact a number of factors, including the relative curtailment of government services, have at least temporarily reversed this trend. We have therefore analyzed the implications for energy demand in Canada of an economic structure which evolves more strongly in the direction of the production of goods than it has in the recent past.

Subsequent chapters develop and provide the rationale for the major assumptions and the approaches taken to analyze the outlook for energy demand and supply of major energy commodities; this also includes assessments of renewable energy forms and gaseous emissions resulting from the production and consumption of energy in Canada. Principal findings are discussed and selected comparisons are made with previous Board reports and the views of others.

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5   National Energy Board, *Review of Inter-Utility Trade in Electricity*, January 1994.

MACROECONOMIC ASSUMPTIONS

Canadian economic growth and the evolution of the structure of the Canadian economy are key determinants of Canadian energy demand over the period studied in this report. Our assumptions represent mid-range, roughly consensus, views of long-run determinants of economic growth. The outlook presented in this chapter is not a forecast; instead, it represents an internally consistent set of assumptions required for our analysis of energy demand.

In this chapter, we present a brief discussion of the international environment, followed by a more detailed discussion of the projected evolution of the Canadian economy. Next, in the Canadian context, we focus on the balance between goods and service industries and introduce an alternative view of future macroeconomic prospects which forms the basis for the Alternative Macro case for energy demand. Finally, we describe our reference case assumptions for the economies of the individual regions of Canada, highlighting the unique characteristics and determinants of economic growth for each.

2.1 INTERNATIONAL ECONOMIC ENVIRONMENT

Over the next 15 years economic growth in the OECD is projected to be moderate, in the neighbourhood of 2.5 percent per year. Most important for Canada are the economic prospects in the United States since over 70 percent of Canadian merchandise exports go to the US. Based on our assessment of the consensus of projectons including that of the OECD Secretariat, economic growth in the United States is assumed to average about 2.5 percent over the long term. This growth is combined with moderate inflation and relatively low nominal interest rates.

It is widely anticipated that the economies of the newly industrialized and developing world will continue to grow more rapidly than the developed countries of the OECD. In the medium-term, many analysts speculate that China will lead the world with economic growth averaging upwards of 8 percent per year thereby becoming an increasingly important market for imports and a source of exports. The newly industrialized countries of Asia including South Korea, Taiwan, Malaysia, Indonesia, Thailand and Singapore are also anticipated to continue robust economic growth in the range of 4-6 percent per year. Economic performance

in Latin America is likely to improve in the future. Greater stimulus to the prosperity of the entire region will occur if Latin American countries join the North American Free Trade Agreement.

The outlook for the FSU represents the greatest uncertainty of all regions in the world. We have assumed that poor economic performance will likely continue through the 1990s but that recovery will occur around the turn of the century, although there is considerable uncertainty regarding the timing of such a turn around. The pace of economic reform and therefore economic recovery will be largely linked to the success of the political process.

The countries of Eastern Europe are at different stages on the road to improved economic performance but most appear to be further advanced than the FSU. Poland and Hungary are poised to begin a period of economic growth because of aggressive reform strategies and strengthening links to capitalist systems. Other countries such as Romania and Bulgaria appear to have significant restructuring still ahead before they can experience improved economic growth.

2.2 CANADIAN ECONOMIC OUTLOOK

Long-run potential economic growth is largely determined by growth in the fundamental determinants of the level of economic output – the labour force, the capital stock and productivity. Growth in the labour force is a function of population growth which includes immigration, the age structure of the population and labour force participation rates. Productivity advancements depend largely on improvements in the skills of workers and changes in technology, while capital accumulation depends on rates of saving and investment.

In developing a set of macroeconomic assumptions, our approach has been to allow the "slackness" which existed in labour markets at the beginning of the projection period to be reduced. This allows economic growth to exceed potential, particularly during the "recovery" phase which ends by 2000. Naturally, cyclical ups and downs will occur over the next 20 years but we have made no attempt to account for the possibility of such swings in our assumptions.

Canada's population is assumed to grow 1.1 percent per year despite the fact that the domestic fertility

rate is projected to be 1.8, somewhat below the population replacement rate. Projected population growth is supported by continued strength in gross international immigration which averages just under 250 000 per year, slightly above the 237 000 recorded in 1992. At the same time, the level of emigration is assumed to increase through the decade reflecting some tendency of immigrants to return to their countries of origin as they reach retirement age and emigration to the US. Assumed emigration levels increase from 38 000 in 1992 to stabilize at 94 000 by the end of the decade. Net-immigration falls from 194 000 in 1992 to 156 000 by the end of the century and remains at that level for the duration of the projection period.

The number of households increases more rapidly than the population – 1.6 percent per year – as the trend towards fewer people per household continues. This reflects higher levels of immigration, the general aging of the population as well as evolving societal attitudes which have led to a higher average age for marriages and increasing divorce rates.

The Canadian labour force grows 1.3 percent per year, just slightly faster than population growth. Over the last 15 years the labour force grew at close to twice the rate of population growth largely because of rapidly increasing female participation in the labour force. This trend is expected to slow as the rate of increase of female participation in the work force slows. The male participation rate declines slightly over the projection period because of a continued trend towards earlier retirement. The net result is that the total labour force participation rate is expected to increase only slightly from 66.3 percent in 1991 to 66.6 percent at the end of the projection period.

Growth in total factor productivity (TFP) rises from near stagnation over the last 15 years to close to one percent per year over the projection period. Future trends in TFP are difficult to estimate. Our assumption reflects a general view that the implementation of major trade agreements such as the FTA, NAFTA and the continued evolution of the GATT will lead to continued industrial rationalization and cost control, higher levels of investment and a shift of Canadian production towards the manufacturing sector with an associated beneficial impact on productivity.

All of the analysis conducted for this report assumes unchanged policy. In the economic sphere, this means that governments at all levels continue to pursue current policy goals. Fiscal policy is assumed to remain focused on restraint over the medium term as governments at both the federal and provincial levels struggle with large deficits and high levels of debt. Limits on government spending are expected to hold growth of the government sector to no more than 1.5 percent per year which is less than in other sectors of the economy resulting in a decline in the contribution of the government sector to overall economic activity.

The combination of restrictive fiscal policy with a continued monetary policy which is focused on price stability leads to low levels of inflation over the

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TABLE 2-1
Key Economic Variables
Average Annual Growth Rate (Percent)

	1976 – 1991	1991 – 2010
Population	1.2	1.1
Households	2.2	1.6
Participation Rates*	66.3	66.6
Male*	74.8	72.8
Female*	58.2	60.6
Labour Force	2.0	1.3
Employment	1.8	1.5
Unemployment Rate*	10.3	7.4
Total Factor Productivity	-0.1	0.8
Inflation – CPI	6.7	2.2
Canadian $ *	0.87	0.79
RDP	2.6	2.5

* Denotes end of period level.

projection period. Inflation, as measured by rate of change in the CPI, averages 2.2 percent per year. Real and nominal interest rates are relatively low reflecting the moderate inflation and the success of the monetary authorities in reducing inflation expectations. For example, the prime rate for business loans gradually declines from its present level to reach 4.5 percent by the end of the projection period.

It is difficult to forecast exchange rates with any degree of precision. For our analysis, we assumed that the Canadian dollar exchange rate would remain constant at the $US0.79, the level at the time our assumption was made. Although the rate has fallen to about $US0.72 in recent months, our assumption is nevertheless consistent with the views of many consultees that the underlying fundamentals imply a rate near $US0.80.

Real personal disposable income growth averages 2.3 percent per year over the projection period, and, with an average annual growth rate of 1.6 percent in the number of households, annual growth in real personal disposable income per household averages 0.7 percent.

We define the interval 1993 to 1998 to be the period of recovery from the 1990-92 recession. During this period, the Canadian economy grows at an average annual rate of 3.3 percent, as it absorbs some of the labour force slack that was created by the 1990-92 recession. After the recovery period, RDP growth moderates so that growth averages 2.5 percent per year during 1991-2010, close to the long-term potential rate.

Average annual economic growth is slightly stronger in the current report than assumed for our Supply and Demand report released in 1991. The level of economic activity however, remains lower throughout the projection period because of the loss in output produced by the 1990-92 recession. The difference in economic activity between the two reports narrows from 5.5 percent in 1991 to just over 2 percent by 2010.

2.3   THE GOODS AND SERVICES BALANCE

The distribution of total output between goods and service industries in the Canadian economy is important in our analysis since differences in industry shares have implications for total energy demand. On average, the production of goods requires roughly five times more energy per dollar of RDP than the production of services.

Over the last 20 years, as in most industrialized countries, the service sector in Canada grew more rapidly than the goods sector. Between 1974 and 1980, the service sector grew 6.1 percent per year, on average, while the goods sector contracted 0.3 percent per year (Table 2-2). Within the service sector, the output of business service industries grew at more than twice the rate of that of the non-business service sector. In the 1980s, the goods sector recovered somewhat and grew 1.3 percent per year, on average, while service sector growth moderated to 2.7 percent. The net result was that by 1991 the service sector accounted for 72.7 percent of RDP up from 60.7 percent in 1973 while the goods sector's share of RDP had fallen from 39.3 percent to 27.3 percent (Table 2-3).

The rise in the service sector share reflected:

- the expansion of the government sector, public health and education;

- increases in the female participation rate with an associated increase in market demand for services formerly produced in the home;

- evolving consumer tastes leading to the production of new services over the last two decades;

- an increasing tendency for businesses to contract out for some types of business services;

- increased competition from less developed countries in the goods producing industries; and

- a greater contraction of the goods sector in the 1990-91 recession.

There are two competing views with respect to the future evolution of the balance between the goods and service industries:

(1)   The trend towards an even higher share of services will continue, reflecting:

- increased demand for health care and consumer services such as tourism and financial services as a result of both the aging population and evolving consumer tastes;

- a continued increase in the female participation rate;

- the migration of low skilled manufacturing to low wage countries; and

- rapid growth in information based industries.

(2)   The trend to a higher service sector share will slow or perhaps even reverse. This change in trend could occur as a result of developments such as:

- increasing merchandise exports as a result of recent trade liberalization. Freer trade will certainly affect

services as well; however, most analysts, including those we consulted, expect a greater impact on goods exports because of Canada's comparative advantage in the production of resource-based goods and in some secondary manufacturing industries;

- tax reform which improved the cost competitiveness of Canadian goods in both export and domestic markets;

- limited growth in the government sector due to fiscal restraint; and

- stronger growth in the goods sector as the economy recovers from recession.

TABLE 2-2

Evolution of the Goods/Services Mix – Sector Growth Rates

Average Annual Growth Rate (Percent)

	Goods Sector		Service Sector					
			Business Services		Non-Business[1] Services		Total Services	
1962-1973	6.9		5.0		4.9		5.0	
1974-1980	-0.3		6.6		2.4		6.1	
1981-1991	1.3		3.0		1.7		2.7	
	Ref[2]	Alt[3]	Ref	Alt	Ref	Alt	Ref	Alt
1993-1998	3.7	4.3	3.6	3.6	1.9	1.0	3.2	3.0
1999-2010	2.5	3.1	2.5	2.4	1.4	1.1	2.3	2.1
1991-2010	2.8	3.4	2.7	2.6	1.5	1.1	2.4	2.3

1 The non-business sector is largely composed of the government sector but is also contains religious and charitable institutions and non-profit organizations.
2 Reference case assumptions
3 Alternative Macro assumption
Source: Statistics Canada, Informetrica and National Energy Board

TABLE 2-3

Evolution of the Goods/Services Mix – Sector Shares

(Percent)

	Goods Sector		Service Sector					
			Business Services		Non-Business[1] Services		Total Services	
1962	35.8		41.7		22.5		64.2	
1973	39.3		39.8		20.9		60.7	
1981	30.0		50.6		19.4		70.0	
1991	27.3		54.3		18.4		72.7	
	Ref[2]	Alt[3]	Ref	Alt	Ref	Alt	Ref	Alt
1998	28.4	29.1	54.8	54.8	16.9	16.1	71.6	70.9
2010	28.8	31.6	56.0	54.6	15.2	13.8	71.2	68.4

1 The non-business sector is largely composed of the government sector but is also contains religious and charitable institutions and non-profit organizations.
2 Reference case assumptions
3 Alternative Macro assumption
Source: Statistics Canada, Informetrica and National Energy Board

To address the contrasting views in our analysis, we have made specific assumptions concerning the rates of growth in the goods sector and in the business and non-business components of the services sector in the post-recovery period and for the remainder of our projection period.

In our Reference case, we have taken the view that the goods sector will grow faster than the rest of the economy over the recovery period largely because these industries closely mirror cycles of economic activity. Industries such as construction and manufacturing experienced the sharpest declines in the recession. As the economy recovers in the 1990s, output in these industries rebounds, registering average annual growth of 3.7 percent, a rate which is more vigourous than the rest of the economy. Consequently, the share of goods producing industries increases from 27.3 percent in 1991 to 28.4 percent in 1998.

During the recovery period, service sector RDP grows 3.2 percent per year, on average, just below the rate for the entire economy for the same period. The business portion of the service sector grows strongly at 3.6 percent per year, close to the rate observed in the goods sector. Increased demand for business sector services results from many of those factors identified in view (1) above. Ongoing fiscal restraint and restructuring at all levels of government results in non-business services growth of only 1.9 percent with the result that growth in the entire service sector is less than that of the goods sector.

After 2000, economic growth in all sectors slows as excess capacity is largely absorbed. At this point, the business sector of the economy begins to resemble the scenario described in (1) above. The share of services produced by the business sector increases from 54.8 percent in 1998 to 56 percent by 2010. However, because of continued restraint in the government sector, the share of non-business services contracts from 16.9 percent in 1998 to 15.2 percent by the end of the projection. The goods sector share increases only marginally from 28.4 percent to 28.8 percent.

Future economic growth could be directed more towards energy intensive goods industries than assumed in our reference scenario for the reasons outlined in view (2) above. To address this uncertainty, we developed an Alternative Macro set of economic assumptions. This case assumes stronger growth in the goods sector relative to the rest of the economy particularly in energy intensive industries. To ensure the sensitivity analysis would reflect only the change in economic structure, overall RDP growth was restricted to about the same rate as in the reference case, 2.5 percent.

In the Alternative Macro set of assumptions, the goods sector rebounds more robustly from the recession growing 4.3 percent per year, on average, over the recovery period with most of the additional growth occurring in export oriented sectors such as pulp and paper and manufacturing. The goods industries' share of total RDP increases from 27.3 percent in 1991 to 29.1 percent in 1998. Growth in the service sector is marginally lower than in the reference case. Business service growth remains at 3.6 percent but non-business service growth drops sharply to 1.0 percent reflecting a more restrictive fiscal environment.

In contrast to the Reference case, goods sector growth in the Alternative Macro case continues to lead all sectors even in the next century. By the end of the projection, the goods sector's share of the economy increases to 31.6 percent. The business service sector growth is similar to that in the Reference case but as in the recovery period, the non-business service sector grows much more slowly. By the end of the projection, the non-business service sector accounts for only 13.8 percent of economic output.

2.4   SECTORAL BREAKDOWN

In the NEB analysis of energy demand, we aggregate industries to correspond as closely as possible to available energy demand data aggregations. The "industrial sector" closely matches "goods producing" industries and includes construction, forestry, mining and manufacturing. The "commercial" sector broadly represents "service producing" industries and includes trade, finance, business and personal services, hospitality, education, health and public administration.

In the NEB Energy Demand Model (EDM), energy demand is estimated and projected using relevant variables which, among others, include sectoral RDP. For example, commercial energy demand is projected using assumptions about future growth in commercial RDP. Energy demand in the rail industry is a function of economic activity in industries which use rail transportation to move goods to market. In EDM, these industries include agriculture, forestry, manufacturing and mining.

Using these definitions of economic structure, we see a story similar to the goods versus services unfold. Between 1973 and 1991, the commercial sector grew 3.0 percent per year resulting in its share of the overall RDP increasing from 48 percent in 1973 to just under 50 percent in 1991 (Tables 2-4 and 2-5). The industrial sector grew more slowly resulting in its share declining from 40 percent in 1973 to 28 percent in 1991.

In both sets of macroeconomic assumptions, the industrial sector grows more rapidly than the commercial sector resulting in an increase in its share of RDP. In the Reference case, most of the industrial sector gains occur in the recovery period as growth accelerates in a number of cyclically sensitive industries. Between 1993 and 1998, the construction sector grows most strongly at 5.7 percent per year followed by the manufacturing sector at 4.5 percent. The entire industrial sector grows 4.3 percent per year. The commercial sector grows only 2.9 percent per year largely because of public sector restraint. In the period 1999 to 2010, industrial sector growth slows to 2.5 percent per year but is still faster than growth in the commercial sector, which slows to 2.2 percent per year. By 2010, the industrial sector comprises 30 percent of RDP while the commercial sector's share has fallen to 48 percent.

In the Alternative Macro sensitivity, the shift from the commercial to the industrial sector is more pronounced due to increased growth in energy intensive industries. Between 1991 and 2010, industrial RDP growth increases to 3.4 percent per year while

TABLE 2-4

Economic Growth by Sector

Average Annual Growth Rate (Percent)

	Reference				Alt Macro		
	1973-1991	1993-1998	1999-2010	1991-2010	1993-1998	1999-2010	1991-2010
Industrial	0.8	4.3	2.5	2.9	5.0	3.1	3.4
Forestry	1.0	1.7	1.7	2.0	2.5	2.6	2.7
Mining	-2.7	1.5	1.2	1.6	1.8	1.5	1.9
Manufacturing	1.3	4.5	2.9	3.3	5.3	3.7	4.1
Construction	3.1	5.7	2.1	2.4	6.3	2.0	2.5
Commercial	3.0	2.9	2.2	2.3	2.6	2.0	2.1
Total	2.8	3.3	2.3	2.5	3.4	2.4	2.6

Source: Statistics Canada, Informetrica and NEB.

TABLE 2-5

Share of Total RDP by Sector

(Percent)

			Reference		Alt Macro	
	1973	1991	1998	2010	1998	2010
Industrial	39.8	27.9	29.4	29.9	30.2	32.6
Forestry	0.8	0.6	0.6	0.5	0.6	0.6
Mining	10.8	4.0	3.8	3.4	3.9	3.6
Manufacturing	22.3	17.1	18.7	19.9	19.3	22.3
Construction	5.9	6.2	6.2	6.0	6.4	6.1
Commercial	47.7	49.7	48.3	47.5	47.5	45.3
Other	12.4	22.4	22.3	22.6	22.2	22.1
Total	100.0	100.0	100.0	100.0	100.0	100.0

Source: Statistics Canada, Informetrica and NEB.

commercial RDP growth slows to 2.1 percent. By 2010, the industrial sector accounts for 33 percent of RDP while the commercial sector share declines to 45 percent.

2.5   THE REGIONAL OUTLOOK

Economic growth follows a similar pattern to both population growth and growth in the provincial labour forces over the projection period. Over the last fifteen years, the labour force grew substantially faster than population in every province because of increased female participation in the workforce. In our projections, this trend slows and labour force growth more closely mirrors population trends.

Disposable income per household increased over the most recent fifteen year period with the exception of Québec and Saskatchewan (Table 2-6). In both these provinces, the decline in disposable income is entirely due to severe drops observed in 1991 because of the recession. Disposable income per household grows moderately in each province over the projection period.

Population growth in Atlantic Canada, at 0.3 percent, is the slowest in the country over the projection period. This is the result of continued high levels of inter-provincial emigration, low levels of international immigration and low birth rates. The continued propensity of Atlantic Canadians to emigrate from the region reflects the limited economic and employment opportunities in the region. Slow population growth results in the slowest labour force growth in the country (0.5 percent). Labour productivity, on the other hand, is projected to increase at the national average rate (1 percent per year). The net effect of very weak demographics, average labour productivity gains and heavy reliance on primary industries such as fishing, results in average annual growth in the Atlantic economy growing only 1.7 percent over the projection period.

Québec's population grows at a rate lower than the national average as birth rates decline and net-immigration stabilizes at around 40 000 per year. Below average population growth (0.8 percent) and a more rapidly aging population than the national average lowers participation rates and leads to below average growth in the Québec labour force (0.9 percent). Labour productivity on the other hand grows slightly faster than the Canadian average because of strong growth in the highly productive manufacturing sector. These factors result in an average annual expansion in the Québec economy of 2.3 percent, just below the national average rate.

TABLE 2-6

Key Economic Variables by Province

Average Annual Growth Rate (Percent)

	Atl	Que	Ont	1976-1991 Man	Sask	Alta	BC
Population	0.4	0.7	1.3	0.4	0.5	2.2	1.9
Households	2.0	2.2	2.1	2.2	1.5	3.1	2.7
Labour Force	1.8	1.6	2.1	1.3	1.4	3.0	2.7
Employment	1.6	1.3	1.8	1.0	1.2	2.7	2.6
Labour Productivity	0.7	0.8	0.7	0.7	0.9	-0.8	0.1
Disposable Income/household	0.7	-0.2	0.6	0.6	-0.4	0.7	0.4
RDP	2.3	2.1	2.5	1.7	2.1	1.9	2.7

	Atl	Que	Ont	1991-2010 Man	Sask	Alta	BC
Population	0.3	0.8	1.4	0.7	0.7	1.3	1.7
Households	0.7	1.2	1.9	1.2	0.8	1.8	2.3
Labour Force	0.5	0.9	1.6	0.8	0.6	1.5	1.9
Employment	0.7	1.2	1.7	1.0	0.6	1.6	2.1
Labour Productivity	1.0	1.1	1.2	1.1	0.9	0.6	0.7
Disposable Income/household	0.8	0.5	0.7	0.7	0.8	0.6	0.4
RDP	1.7	2.3	2.9	2.1	1.6	2.3	2.9

Ontario experiences higher than average population growth over the projection period because of higher than average birthrates and the highest net-immigration, in absolute numbers, in the country. Ontario has traditionally been a favoured destination for both international and inter-provincial migrants because of the availability of economic opportunities. We expect this trend to continue and assume net international and interprovincial migration to average 90 000 to 100 000 persons per year. Labour productivity grows 1.2 percent, the fastest rate in the country, largely because economic growth is led by the newly restructured manufacturing sector. Because the recent recession affected Ontario most severely, the gap between current and potential growth is greater than in other regions and therefore Ontario displays the strongest rate of growth over the recovery period (1993 to 1998). The combination of positive demographic factors with increasing productivity allows the Ontario economy to be among the fastest growing over the projection period (2.9 percent).

Manitoba has historically had one of the more balanced provincial economies with its economic structure closely matching that of the country as a whole. Manitoba's population grows more slowly than the national average at 0.7 percent per year largely because of low levels of immigration. Similarly Manitoba displays slow average annual labour force growth (0.8 percent). Labour productivity, on the other hand, grows 1.1 percent per year on the strength of the continued expansion of the manufacturing sector. Agricultural sector performance is a moderating influence on real output growth. These factors result in RDP growth of 2.1 percent per year over the projection period.

In Saskatchewan, future real output growth is limited by factors similar to those which affect the Atlantic provinces. These include dependence on primary industries (agriculture and mining in the case of Saskatchewan), for which the prospects are not particularly favourable, and slow population and labour force growth reflecting high rates of net emigration. Population and labour force growth are well below the national average at 0.7 percent and 0.6 percent, respectively. Labour productivity increases at an average rate of 0.9 percent. The net effect of all these factors is average annual real output growth of 1.6 percent.

After leading the country for the last 15 years, Alberta's population growth slows to 1.3 percent per year over the projection period, lagging behind both Ontario and B.C.. In part, the slowing in population growth is due to lower net-immigration levels than in the 1970s. The Alberta labour force grows more rapidly than the population, 1.5 percent per year, largely because the Alberta population is younger than that of other regions of the country. Nevertheless this is only half the rate recorded over the previous two decades. Labour productivity growth of 0.6 percent is the lowest in the country but this reflects sectoral shifts in real output growth (an increased service sector share) rather than reduced productivity growth in any particular industry. In fact, recent and ongoing restructuring should increase productivity in the already highly productive oil and gas industry. A similar shift in industry shares occurred between 1976 and 1991 as the oil and gas sector's share of provincial RDP dropped from 31 percent to 18 percent and average labour productivity actually declined 0.8 percent per year, on average. The combination of strong population growth with weak labour productivity growth results in average annual RDP growth of 2.3 percent.

British Columbia's population and labour force exhibit the strongest growth in the country at 1.7 percent and 1.9 percent respectively. Both are sustained by continuing trends of high international and inter-provincial migration as people continue to be attracted to the province's relatively amiable climate and by economic opportunity. Labour force productivity rises more slowly than the national average, 0.7 percent per year, as the labour intensive service sector expands. Buoyed by strong demographic fundamentals, provincial RDP growth leads the country at 2.9 percent per year.

ENERGY PRICES

The price of energy is particularly important to Canadians because of the significant energy requirements arising from Canada's extreme climate and high concentration of energy intensive industries; high energy costs can be a handicap. On the other hand, Canada also has a large energy-producing sector so energy prices and the profitability of energy production have important implications for economic activity and employment in the major energy producing regions. For energy producers, the prices which are important are the wellhead or fieldgate prices while for consumers, the important prices are at the burner tip. Final consumers of energy have choices among various energy commodities to satisfy their needs. Their choices depend on the relative prices of these commodities at the burner tip.

This chapter first examines wellhead prices for international crude oil and North American natural gas. Next, we look at burner tip prices including petroleum products, natural gas, electricity, coal and alternative and renewable fuels. The chapter concludes with a discussion of efficiency adjusted energy prices in key competitive markets.

3.1 INTERNATIONAL CRUDE PETROLEUM PRICES

Although the energy sector is important to the Canadian economy, Canada is a very small player in international oil markets, accounting for only 2 percent of world demand and 3 percent of supply. Consequently, Canada can truly be regarded as a price taker in crude oil markets. Most Canadian crude oil exports go to the mid-western U.S. and compete with U.S. crude on a delivered basis in Chicago. Consequently, the most important benchmark price for Canadian producers is the price of WTI. Canadian crude in the U.S. and WTI also compete with imports from offshore, particularly in eastern markets. This establishes an interdependence between the prices of North American crudes and imports from around the world. Any analysis of oil prices in Canada must therefore take account of market conditions in the international context.

Over the past 20 years, the market for crude oil has been characterized by many buyers facing two types of suppliers characterized by the supply cost of their crude oil resources. Through OPEC, the world's low-cost producers have acted to restrict supply and sustain prices above their competitive levels. However, the market power of OPEC has been increasingly limited by the higher cost suppliers in the rest of the world. These suppliers have been increasingly competitive, setting output levels at the point where the market price equals their marginal cost. Consequently, the higher the price which OPEC targets, the larger the quantity of crude oil that will be profitably produced by these suppliers. This has resulted in a reversal in the order of production between low and high cost producers. Higher cost producers (outside of OPEC) produce essentially all they want as long as it is profitable (i.e., they cover their marginal costs), while the lowest cost producers curtail their output in order to sustain higher prices.

3.1.1 History of World Oil Markets

Over the past century and a quarter, the price of crude oil has generally varied within a narrow range between US$10 and US$20 in 1993 dollars. (Figure 3-1) The last 20 years however, have been characterized by significant volatility reflecting political instability both within and outside the Middle East, varying degrees of OPEC cohesiveness and strategy, the response of non-OPEC supply, slower world economic growth, energy conservation, fuel switching and technological change leading to reduced supply costs.

World oil markets continue to be influenced by political events in the 1990s. The price of oil more than doubled in the months leading up to the Gulf War, reaching a peak of US$42 per barrel in October of 1990 as over 4 million barrels per day of production from Iraq and Kuwait were removed from world markets. However, a number of OPEC countries responded differently to this situation than during similar disruptions in the past. Fearing a repeat of the early 1980s in which OPEC lost market share largely because of high prices, Saudi Arabia and other OPEC countries made every effort to replace the lost production. As a result, the price of oil experienced only six months of volatility and by December 1990 it had subsided to about US$27 per barrel.

Following the allied invasion of Iraq in the beginning of 1991, the price of oil plunged. As markets were assured of an allied victory, WTI settled at just under US$20 in March of 1991 and traded within the

narrow range of US$19 to US$23 per barrel over the following two years. Beginning in March of 1993, the price of oil began an almost uninterrupted nine months slide. The rate of decline accelerated towards late fall and by December WTI averaged less than $15 US. The softness in prices in 1993 reflected the inability of OPEC to re-allocate quota to accommodate increasing production from Kuwait, production increases from non-OPEC sources, particularly the North Sea, unexpected steady net-exports from the Former Soviet Union and weak world demand. The price was further influenced by expectations that Iraq would soon be allowed to return to world oil markets.

Most recently, the price of oil has regained the ground it lost in 1993; in June 1994, WTI averaged just over US$19 per barrel. A cold winter in North America largely reduced inventories and economic recovery has led to higher sustained demand. Combined with fairly strict adherence by OPEC members to quotas, these factors have resulted in firmer prices.

3.1.2   Sustainable Range

As in the 1991 report, our approach to the analysis of international petroleum markets is to establish a "sustainable range" for international crude prices based on the underlying fundamental forces affecting supply and demand. The actual price of crude will, of course, fluctuate and could lie outside the estimated sustainable range from time to time even if our analysis is generally correct. For example, the price could fall below the

bottom of the range for some time depending on the reaction of OPEC and other market participants to a return of Iraqi production to world markets. However, at points beyond these boundaries, we expect that OPEC behaviour and market forces should act to return the price of oil within this sustainable range.

Based on information gathered and a survey of other forecasting agencies, energy demand growth should be moderate over the projection period and should not, by itself, lead to escalating oil prices. We therefore focus the majority of our analysis on supply costs of crude petroleum both in the Middle East and the rest of the world as the key determinant of future oil prices. Given the large amount of crude thought to be available at supply costs of less than US$30, we believe that under any plausible outcome for world crude oil demand, the conclusions of analysis based on supply costs and OPEC behaviour are likely to be valid.

World Oil Demand

We have undertaken little independent analysis of world oil demand. However, we have reviewed the work of a number of experts which all forecast oil demand growth to be moderate. In all cases, world oil demand is forecast to grow less than 2 percent per year over the projection period[1] (Figure 3-2). Oil demand should increase most rapidly in the developing world as these economies expand rapidly and most slowly in the

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1   Forecasters include IEA, EIA, CERI, PEL, PIRA.

FIGURE 3-1
Crude Oil Prices
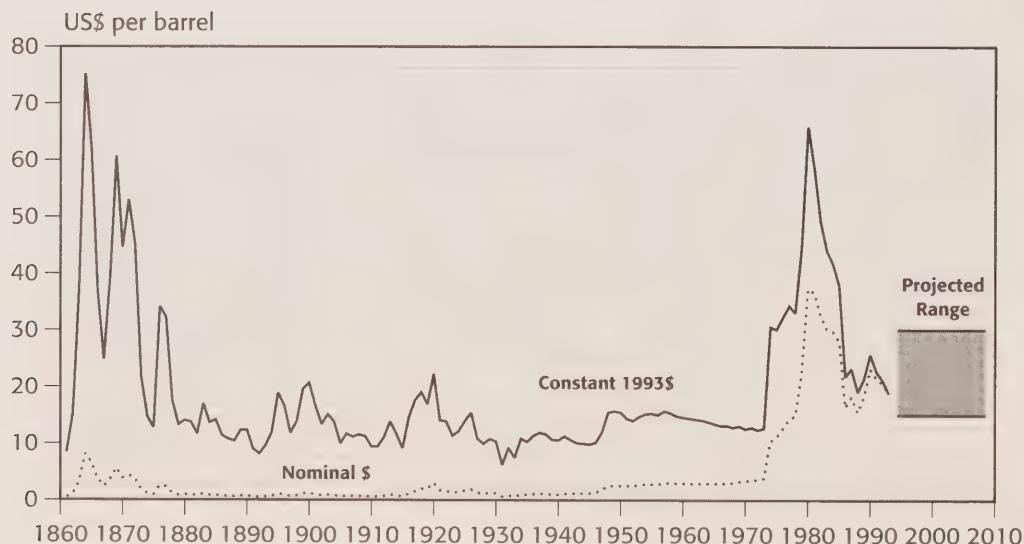
developed countries of the OECD. As a result, the OECD's share is expected to fall from 58 percent of world consumption in 1992 to less than 50 percent by 2010. The impact on world oil demand due to developments and restructuring in the FSU should continue to be a major uncertainty in the years to come.

Oil continues to face increasing competition from a variety of energy sources such as natural gas and coal. Even in rapidly expanding economies, oil is not expected to capture a significant portion of markets characterized by competition between fossil fuels, such as within the boiler, space heating or the petrochemical feedstock market. Instead, most incremental oil demand should occur in the transportation sector where little inter-fuel competition exists for oil. Demand for transportation services, and therefore transportation fuels, should increase most rapidly in countries with growing populations combined with strong economic and disposable income growth.

Non-OPEC Supply

Non-OPEC oil production most closely resembles a competitive market where no individual producer holds market power to influence prices. These producers are mainly concerned with the profitability of production. Output in non-OPEC countries has been surprisingly resilient in recent years despite consistently lower oil prices post-1985. Non-OPEC production has been enhanced by important improvements in technology which have lowered the costs of finding and producing oil. These technologies include horizontal drilling, 3-D seismic and, in the case of offshore oil production, floating production systems. An added boost to non-OPEC

production has been the de-nationalization of domestic production which has opened up many regions of the world. To further entice foreign investment, governments have become increasingly flexible in the fiscal regimes which govern oil production.

The effects of some of these cost reductions can be observed in the changing cost of production from Canadian oil sands projects. As late as 1990, synthetic crude from the oil sands projects was estimated to cost close to $32 per barrel[2] while current estimates are significantly lower at $25 per barrel (see Chapter 7). Similarly, Petroleum Economic Limited estimates that both capital and operating costs of North Sea production have been reduced in recent years by over 20 percent through the introduction of new technologies.

At current costs of production, estimates from Petroleum Economics Limited suggest that about 1.34 trillion barrels or 75 percent of the 1.79 trillion barrels of proven and probable conventional reserves outside the Middle East are producible for less than US$25 per barrel and that about 80 percent of the 1.34 trillion barrels will cost more than US$15 to produce. Recent work by other observers generally supports those conclusions, at least qualitatively. This suggests that non-OPEC production would impact OPEC production levels at prices above US$15 per barrel over the longer term (Table 3-1).

All the forecasters surveyed expect non-OPEC production to increase to the end of the century despite very low price projections in some cases. Beyond the year 2000, the range of forecasts is much broader

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2   NEB, 1991 Supply/Demand Report.

FIGURE 3-2
World Oil Demand[1]
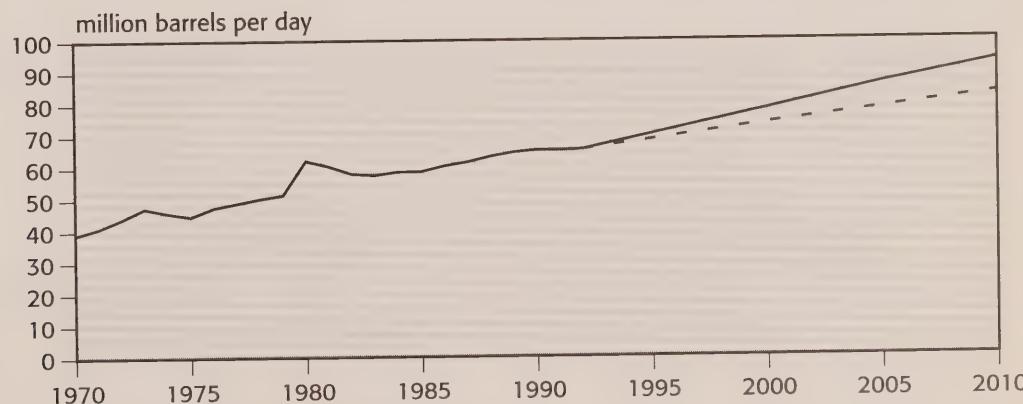
1 Range based on a review of external projections.

reflecting uncertainties about resource size and the rate of change in technology (Figure 3-3).

There is great uncertainty with respect to future oil production in the former Soviet Union. Oil production in the FSU has declined rapidly in the last few years but surprisingly net-exports have remained fairly stable. Predicting when the FSU will recover economically and how that will manifest itself in world oil markets is, in the opinion of most analysts, guess work at best. We have assumed that FSU exports will remain near current levels. This is consistent with continued economic difficulty, which would limit both demand and production or economic revival which would stimulate demand but also allow production to increase to satisfy this demand.

OPEC Supply

The countries of OPEC continue to hold significant market power, controlling almost 77 percent of the world's proven oil reserves. The five major Middle East producers[3] alone account for over 64 percent of the world's proven reserves. Supply costs in the major OPEC producers of the Middle East remain the lowest in the world. Petroleum Economics Limited estimates that 85 percent of the proven reserves in the Middle East are producible under US$5 per barrel, therefore, under any price scenario, the "profitability" of Middle East oil is unquestionable.

Led by Saudi Arabia, OPEC has followed a strategy designed to increase or at least maintain its market share for the last six years. To effectively control market share, OPEC must choose its level of production recognizing that both demand and non-OPEC supply can adjust to price changes. For OPEC, an effective

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3   These countries include Saudi Arabia (25.6 percent), Iraq (9.9 percent), U.A.E. (9.8 percent), Kuwait (9.3 percent) and Iran (9.2 percent).

TABLE 3-1

Supply Cost Estimates of Proven and Probable Reserves

Supply Costs	OECD	Middle East	Asia & Africa	Other Western Hemisphere	Eastern Europe	World
(US$ 1993/bbl)			(billion barrels)			
<14	47	1 055	112	91	20	1 325
15-19	34		41	138	69	282
20-24	126		30	566	61	783
25-29	31			135	55	221
>30	51			128	55	234

FIGURE 3-3

Non-OPEC Oil Production Excluding the FSU[1]
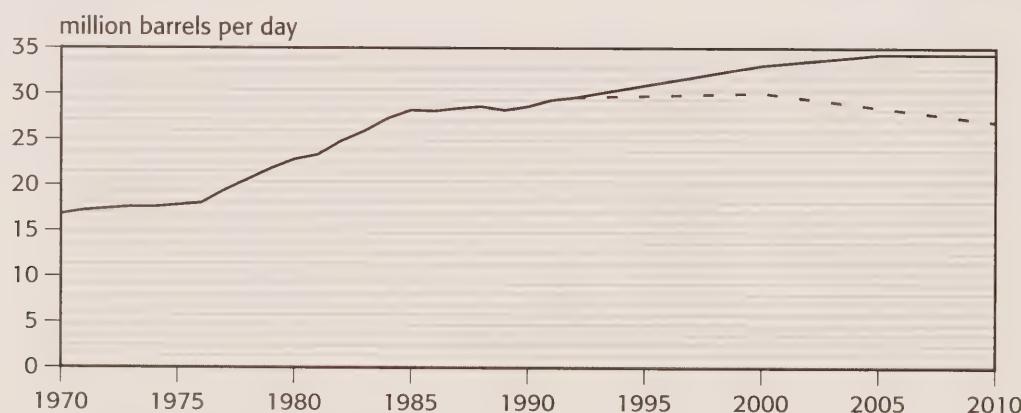
1   Range based on a review of external projections.

market share policy requires moderate prices which discourage substitution away from oil to other fuels as well as dampening the development of non-OPEC supply. As noted above, production costs have been falling in non-OPEC countries over the last few years largely due to the innovative use of technology and more efficient business practices. Therefore an oil price that perhaps was "optimal" in terms of increasing OPEC's market share even three years ago may, in today's environment, be too high.

To effectively manage international crude oil markets, OPEC members must act together cohesively. In reality, because of divergent policies and goals, it has been difficult for the individual members of OPEC to act together. Short-run revenue maximization has long been a key goal in many OPEC nations. In many cases, oil sales are the only source of external revenue and in the case of Iran, Nigeria and Algeria, their ability to import goods is directly linked to revenues from their oil exports. The conflict between the member countries who are short-run revenue maximizers and the more long-run market share maximizers has from time to time disrupted the unity and effectiveness of the group.

OPEC's success in the near-term will also be linked to the group's ability and willingness to accommodate Iraq's return to markets. At the present time, this presents the greatest downside risk to prices as even the threat of Iraq's return has had a negative impact on prices. In the long-term, OPEC's survival will be linked to its ability to reconcile divergent goals and manage its excess supply.

There is surprising unanimity with respect to the outlook for OPEC production over the projection period.

Most of the projections surveyed expect OPEC production to grow within the narrow range of 2.6 percent to 3.2 percent (Figure 3-4). The similarity of forecasts to the year 2000 reflects the fact that capacity expansion plans have already been announced in a number of countries. According to these announcements, OPEC capacity should increase by 7.7 million barrels per day by the turn of the century. Even with flat production in non-OPEC countries, this level of new OPEC capacity would satisfy world demand growing 1.6 percent per year and still allow OPEC to utilize less than 90 percent of its capacity.

The data and analysis presented here suggest that a price ranging between US$15 and US$25 could be sustainable depending on the strategy and cohesiveness of OPEC. Other analysts tend to be in general agreement with this assessment. However, the analysis of a few observers, most notable, the International Energy Agency and the United States Energy Information Administration, present a somewhat higher upper bound for crude prices.

The lower bound of the range of views we surveyed corresponds closely with the US$15 suggested by our analysis but the upper bound lies closer to US$30 than to US$25. Consequently, we have adopted a "sustainable range" of US$15 to US$30 for use in the analysis of price sensitivity of Canadian crude oil supply. All other quantitative analysis done for the report assumes a mid-range price which rises from the 1993 average of under US$19 to US$23 over the course of the projection period.

FIGURE 3-4
OPEC Oil Production[1]
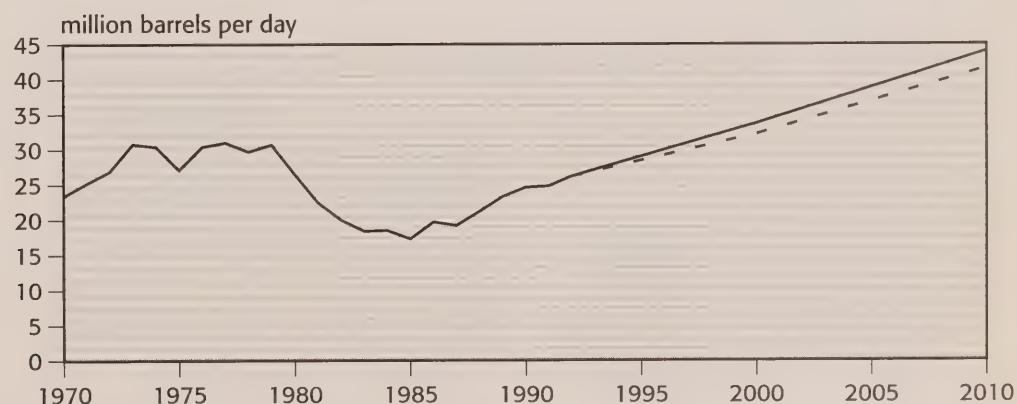
1 Range based on a review of external projections.

3.2 NATURAL GAS FIELDGATE PRICES

Prior to signing of the Western Accord in March 1985, natural gas prices in Canada were determined in a regulated environment. Since that time, Canadian natural gas prices have been determined by competitive forces in a North American market.

Canadian natural gas fieldgate prices were projected by examining both supply and demand conditions for natural gas within the North American context using the North American Regional Gas Model (NARG). In the NARG analysis, Canadian demand was determined through an iterative process by the NEB's Energy Demand Model (EDM) while the Gas Research Institute (Baseline Projection 1993) projection formed the basic assumption for US natural gas demand. A detailed discussion of the NARG analysis is provided in Appendix 6.1.

As discussed in more detail in Chapter 6, we developed two cases corresponding to two different views about the evolution of natural gas supply costs. The Current Tech case was based on an analysis similar to that contained in previous reports in which natural gas supply costs increase steadily over the study period as discovery and development of the resources proceed. The High Tech case recognizes the contribution that improved technology makes to the cost of production. In this case, unspecified technological improvements act to keep supply costs near current replacement levels in real terms.

In the Current Tech case, Canadian fieldgate prices grow 5.8 percent per year reaching $4.11 per gigajoule (1993 dollars) by the end of the projection period from $1.58 per gigajoule in 1993. In the High Tech case, fieldgate prices rise much less rapidly, at an average rate

of 2.1 percent, to reach $2.24 per gigajoule by 2010 (Figure 3-5).

3.3 BURNER TIP PRICES

3.3.1 Petroleum Product Prices

Reflecting crude oil price movements over the last 20 years, petroleum product prices have been highly volatile, increasing significantly in the 1970s but generally declining in the 1980s. Petroleum product prices are the sum of the price of crude, cost of transportation, refinery margins, distribution margins and taxes. In the case of regular grade motor gasoline which averaged 53¢/litre across Canada in 1993, the cost of crude accounted for 26 percent of the pump price while federal and provincial taxes accounted for 49 percent and refining and retail margins accounted for the remaining 25 percent. Petroleum products used for transportation such as gasoline, diesel or aviation fuel tend to be more heavily taxed than other petroleum products.

In general, petroleum product prices rise more slowly than the price of crude oil, less than 1 percent per year in real terms over the projection period. This reflects the assumption that transportation costs, refinery and distribution margins and taxes remain constant in real terms. As with crude oil prices, we assume that petroleum product prices follow the same path in the Current Tech, High Tech and Alternative Macro Cases.

The price of heavy fuel oil (HFO) is the only petroleum product price which increases significantly over the projection period. A premium was added to HFO prices as a way of accounting for the costs of switching from natural gas in the industrial sector. This reflected the view expressed at the Export Impact

FIGURE 3-5
Canadian Fieldgate Natural Gas Prices
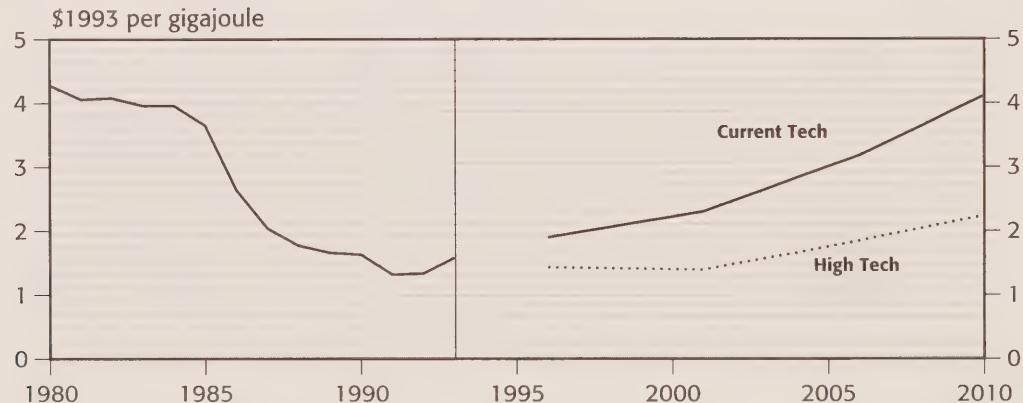
Assessment (EIA) workshop and in our consultation process that the costs of switching could be high because of the need to build infrastructure and to meet environmental standards.

3.3.2 Natural Gas

As with petroleum products, natural gas burner tip prices include transportation and distribution costs and taxes in addition to the fieldgate price. Within the three producing provinces of Alberta, BC and Saskatchewan, transportation costs include only the cost of the intra-provincial transportation system. For the other provinces, transportation includes gathering costs in the producing province, such as NOVA tariffs in Alberta, TCPL tolls and costs of distribution by local distribution companies (LDCs) in the respective provinces.

Distribution costs vary among provinces, within individual provinces and by sector. Distribution costs tend to be lowest for large users in the industrial sector and highest for the small users in the residential sector. Industrial users benefit from low distribution costs because of the large volumes and also because they can obtain discounts from LDCs or in some cases purchase gas directly from the producers at generally lower spot prices.

The combination of transportation and distribution costs plus taxes can make up a considerable portion of the natural gas burner tip price paid by consumers. In the industrial sector in 1993, these charges constituted only 27 percent of the burner tip price in Alberta but in Québec, fully 69 percent of the burner-tip price came from these costs (Figures 3-6 and 3-7). As one would expect, the further east from Alberta one goes the higher

FIGURE 3-6
Composition of Natural Gas Price in 1993 – Alberta
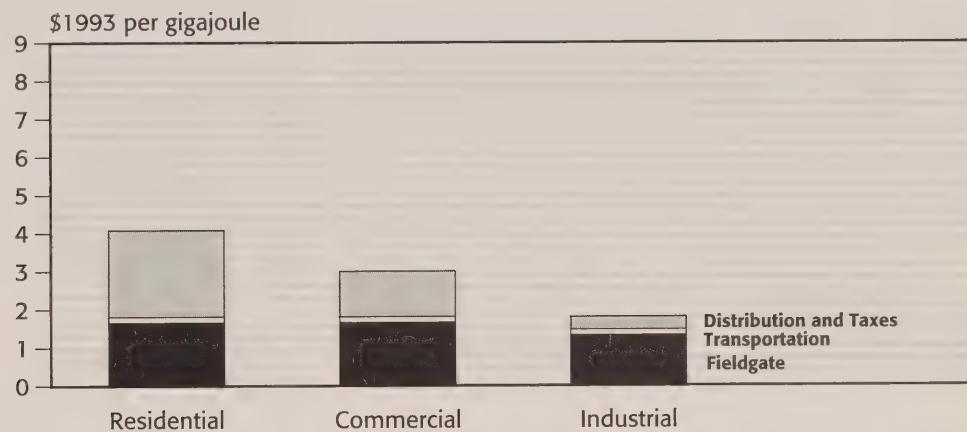
FIGURE 3-7
Composition of Natural Gas Price in 1993 – Québec
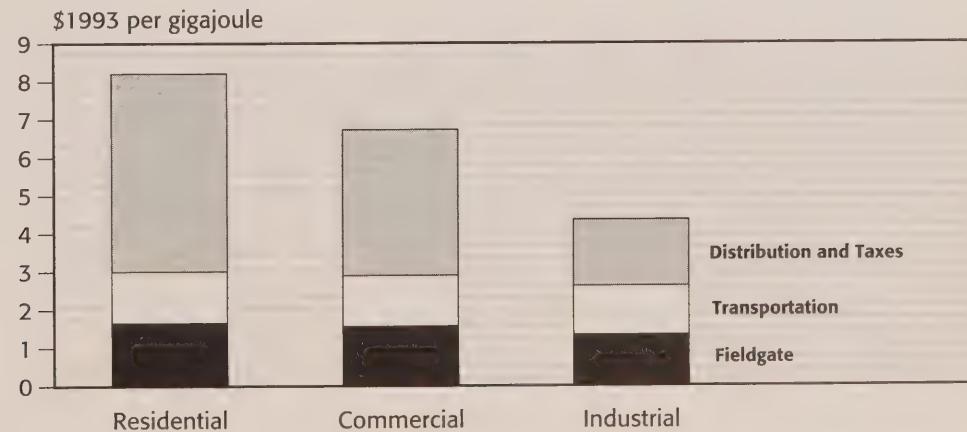
are the transportation costs. A similar story holds in the commercial sector where distribution and transportation costs and taxes comprised 45 percent of burner-tip prices in Alberta and 77 percent in Québec. In the residential sector these charges accounted for 59 percent to 80 percent of the burner tip price respectively.

In formulating our outlook for natural gas burner-tip prices, we assumed transportation and distribution costs to remain constant in real terms and that taxes would remain at current rates throughout the projection period. Any changes in burner-tip prices are therefore the result of changes in fieldgate prices.

Because the fieldgate price makes up only a portion of burner-tip prices, end use prices generally increase at a slower rate. At the burner-tip, the impacts are greatest in the Alberta industrial sector (7.7 percent in the Current Tech case) where the fieldgate price constitutes the largest share of burner-tip prices. Alberta industrial natural gas prices actually increase faster than fieldgate prices because of the province's high proportion of direct sales. The discount for direct purchases that existed during the supply overhang of the late 1980s and early 1990s has diminished leading to an increase in the direct sales price. Burner-tip prices are projected to increase most slowly in the Québec residential sector (1.9 percent in the Current Tech case) because transportation costs and distribution margins are highest in the residential sector.

3.3.3 Electricity Prices

Over the last 20 years, electricity prices in all regions of the country have increased more rapidly than the general price level. In the last few years, several Canadian electric utilities have experienced problems with over-capacity. Generation capacity was added in the latter part of the 1980s based on demand projections that did not materialize. The existence of this excess capacity had the potential to produce significant rate increases but many utilities have recently engaged in major cost reduction exercises to keep rates down.

With the exception of price increases that have already been announced by utilities, electricity prices in all regions and all sectors are assumed to remain constant in real terms throughout our study period. This is the same approach used in the 1991 report. Rising electrical loads during the economic recovery should help to reduce unit costs. Further, supply cost data received from the utilities are generally consistent with constant, real prices in the future even when additions to capacity are required. In general, base load capacity additions are not expected to be required until the latter half of the projection period.

3.3.4 Coal Prices

Following consultation with the industry, we assumed a real price of coal which rises very slightly over the projection period – at an annual average rate of 0.5 percent. This increase is much lower than the rates of increase in the prices of competing fuels. Inter-fuel competition and environmental considerations in combination with abundant supply should act to maintain a low coal price environment.

3.3.5 Alternative and Renewable Energy

Alternative and renewable energy sources include: biomass (i.e., wood, wood waste, spent pulping liquor, municipal solid waste); water (i.e., small hydro); wind; solar radiation; and geothermal and tidal energies.

Like other energy forms, demand for renewable energy will be influenced by its price relative to those of competing energy sources. For our assessment of the potential growth in the use of renewable energy, we gathered data on the estimated supply costs of renewable and compared those costs with the prices of conventional energy forms at the present time.[4]

The costs of renewable energy are estimated on a commercial basis to make them comparable with the prices of conventional energy (See Figure 10-1). We use the market or commercial pricing approach because our objective is to assess energy supply and demand in the context of anticipated market price behaviour. We have not made an attempt to evaluate social cost/benefits or drawbacks arising from renewable or conventional energy sources.

There is a wide range of prices and costs for both conventional and renewable energy forms. In the case of conventional energy, the prices differ dramatically depending on the geographical location at which they are measured. In the case of natural gas this is related to the fact that transportation costs are much higher for eastern markets than for service to western markets. In the case of electricity, generating costs differ widely across the country depending on the type of installed generation capacity. There is an even wider range in the estimated end use costs of some renewable energy sources which are highly site and use specific. The low end of the cost ranges shown in Figure 10-1 represents the most favourable applications of existing technologies.

Clearly some renewable energy forms are competitive with conventional sources and are now being

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4   For details on prices, see Chapter 10.

used, in some cases quite extensively. Much of the renewable energy currently being consumed is in the form of wood and wood wastes used for residential space heating and in the pulp and paper industry, respectively. However, other renewable energy sources have found important niche markets, such as, the use of small photovoltaic systems in remote telecommunications, lighting or monitoring services.

Except for wood and wood waste most alternative energy sources are, in general, still expensive compared with conventional energy when priced on a market basis. Over our study period, however, pricing mechanisms and tax policies could change as could individual preferences in favour of using alternative energy forms. Technological progress could also enhance the commercial viability of alternative energy.

3.4 EFFICIENCY ADJUSTED END USE PRICES

Consumers make their decisions based on both the price of an energy commodity and the efficiency with which it performs a specific function. In order to evaluate the competitive position of diverse energy sources, their price must be adjusted to reflect their relative efficiency in different end uses.

Burner tip prices differ significantly between sectors and among regions. Figures 3-8 through 3-11 show the historical and projected evolution for efficiency adjusted end use prices in Ontario and British Columbia in the residential and industrial sectors.

In the residential sector, natural gas is generally the least cost fuel in both the Current and High Tech cases. Electricity is the most expensive fuel in Ontario but remains cheaper than light fuel oil in BC (Figures 3-8 and 3-9). BC consumers generally enjoy the lowest electricity prices in the country. In Québec, natural gas maintains its relative price advantage to electricity throughout the projection period (Figure 3-12).

In the industrial sector, where interfuel competition is greatest, the most interesting part of the price story relates to prices relative to natural gas, which differ between the Current Tech and High Tech cases. Relative to HFO in Ontario, natural gas becomes a higher-cost alternative under the Current Tech assumptions by about 2005 (Figure 3-10) and by 2009 in BC (Figure 3-11). However, in the High Tech case, gas maintains its price advantage over HFO throughout the projection. Relative to electricity, gas remains the lower-cost fuel in all provinces where it is available; the exception is Québec in the Current Tech case after 2005 (Figure 3-13). Gas has a substantial competitive advantage under the High Tech assumption.

FIGURE 3-8
Residential Energy Prices – Ontario
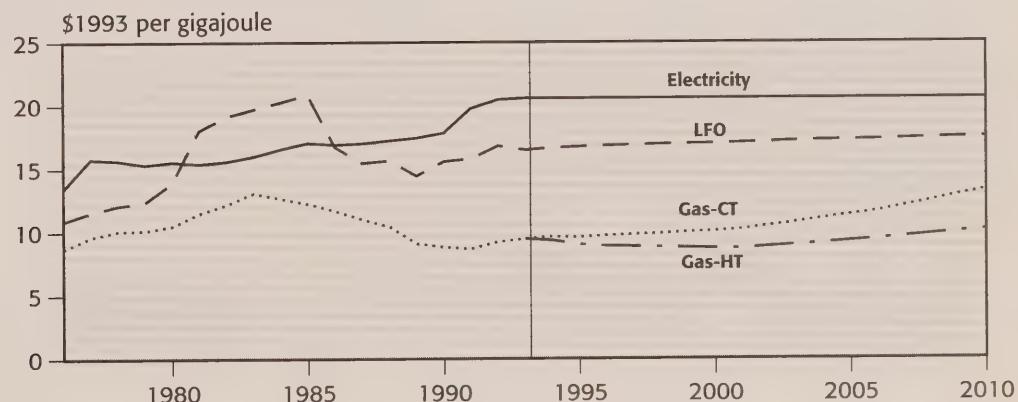
FIGURE 3-9
Residential Energy Prices – BC

$1993 per gigajoule

Lines labeled: LFO, Electricity, Gas-CT, Gas-HT
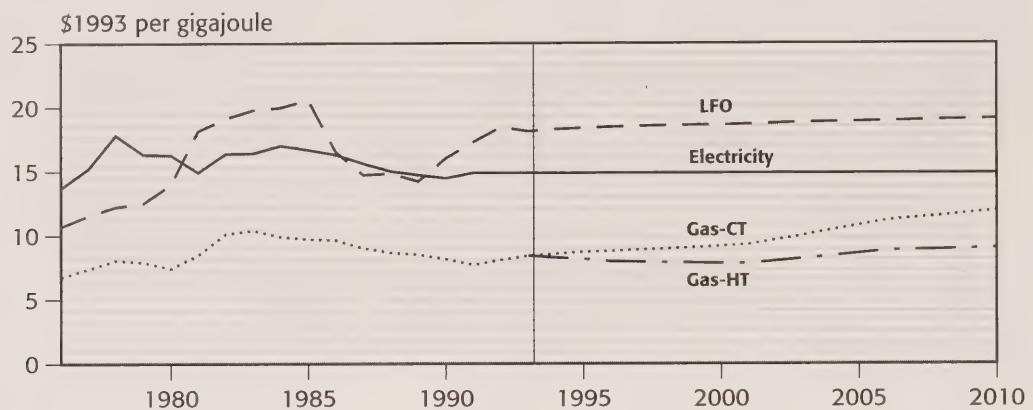
FIGURE 3-10
Industrial Energy Prices – Ontario

$1993 per gigajoule

Lines labeled: Electricity, Gas-CT, HFO, Gas-HT
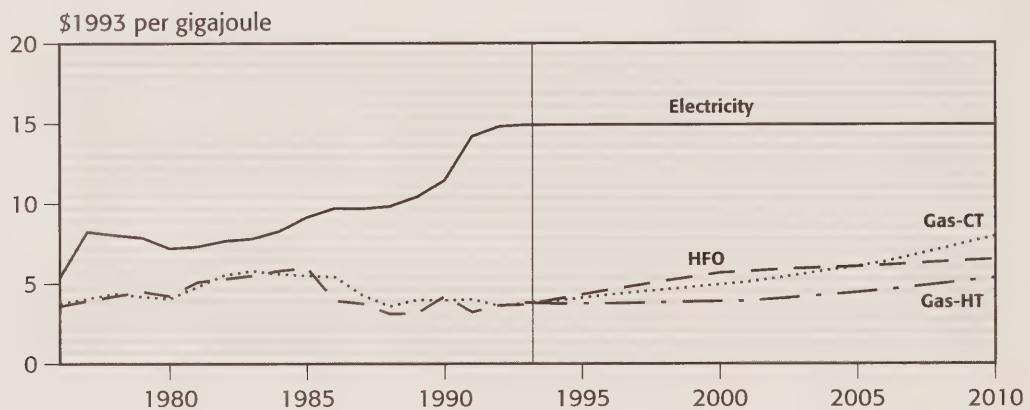
FIGURE 3-11
Industrial Energy Prices – BC

$1993 per gigajoule

Lines labeled: Electricity, HFO, Gas-CT, Gas-HT
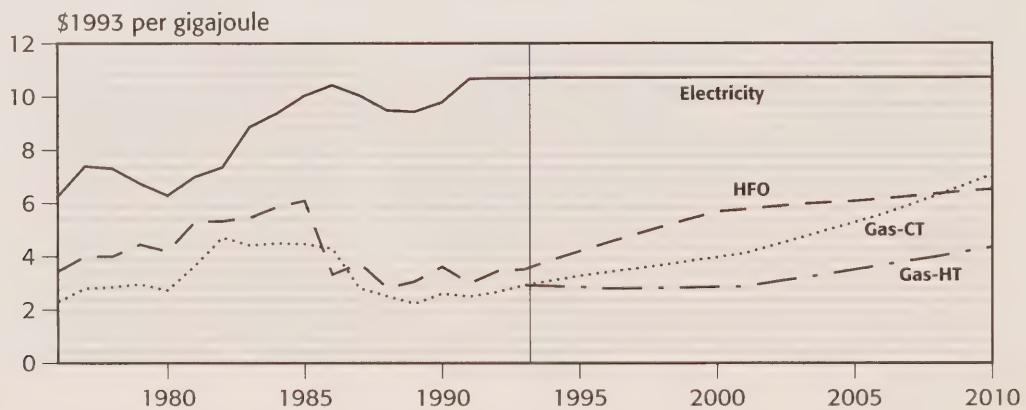
FIGURE 3-12
Residential Price Ratios – Gas to Electricity – Québec
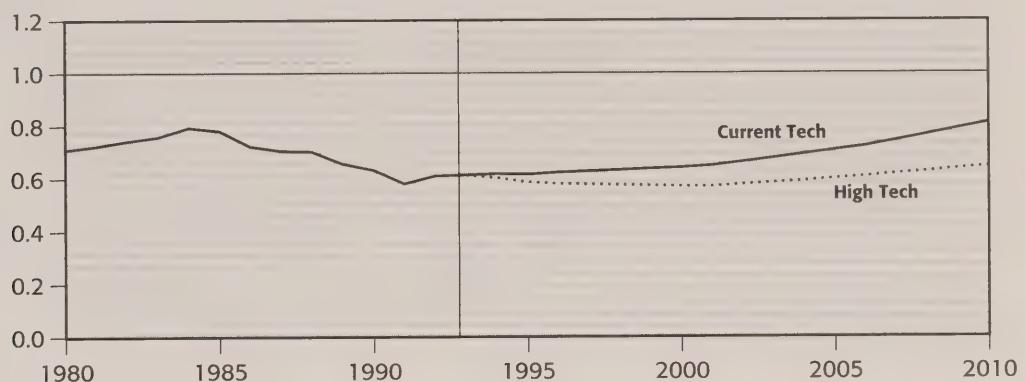
FIGURE 3-13
Industrial Price Ratios – Gas to Electricity – Québec

Chapter 4
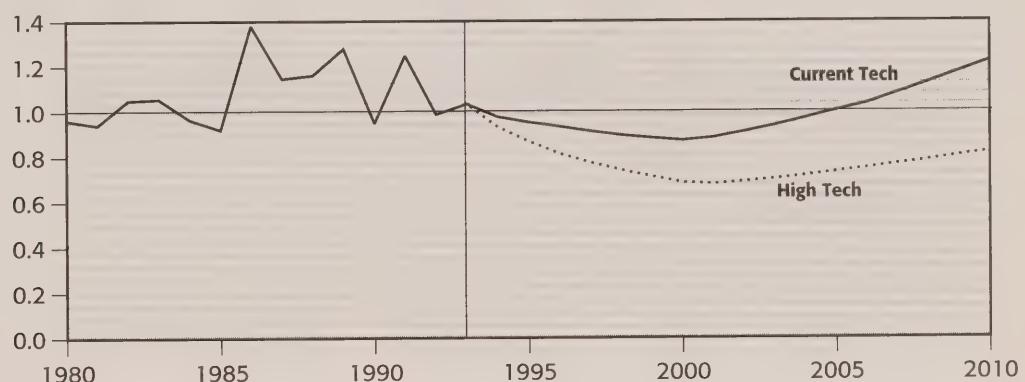
CANADIAN ENERGY DEMAND

4.1   INTRODUCTION

An analysis of domestic energy demand is an important component in an overall study of energy issues. Growth in total energy demand has a strong influence on the rates of development of the upstream gas and petroleum sectors and the electric power generation sector. The pattern of energy demand also influences the required mix of energy fuels. For example, the ongoing growth in the use of office equipment and home appliances that are powered by electricity has implications for future electricity requirements, whereas the rate of homebuilding has implications for space heating requirements and, hence, the call on natural gas supplies.

Energy demand is derived from and is therefore dependent upon the demand for goods and services such as transportation, space heating, lighting and the myriad of applications which are powered by energy in our modern economy.

This chapter identifies and discusses the major factors which influence energy demand, and analyzes the implications of changing patterns in our economy for both the level and composition of future energy demand.

In Section 4.2, we provide a historical review of overall energy demand patterns. Section 4.3 provides a brief outline of the major factors which influence energy demand and major uncertainties which we address in this report. A summary description of our demand projections is provided in Section 4.4. Section 4.5 then

provides a detailed breakdown of both the history and outlook for energy demand in each sector: residential, commercial, industrial, transportation, and "non-energy" (primarily petrochemicals, asphalt, lubes and greases). In Section 4.6, we provide a breakdown of demand by the major consuming regions. Section 4.7 discusses the shares of total energy demand that will be held by each fuel under the major cases analyzed. Finally, we provide a summary of our major observations in Section 4.8.

4.2   HISTORICAL TRENDS

The determinants of energy demand include the level and structure of economic activity, demographic trends, energy prices, the efficiency of energy use, government policy and the evolution of consumer tastes and behaviour. In the last two decades, changes in each of these factors have strongly affected both the growth and patterns of energy use.

Prior to the early 1970s, energy demand increased rapidly as the economy grew strongly and energy prices remained low. Since the oil price shock of 1973 and also in response to the further shock of 1979, the pattern of energy use has changed significantly. The post-1973 era has been characterized by slower economic growth including two deep recessions and higher and more volatile energy prices. The effects of these changes on energy demand are illustrated in Figure 4-1. In contrast to the period of low cost energy, consumers of energy began to focus more on conservation and efficiency

FIGURE 4-1
Canadian End Use Energy Demand
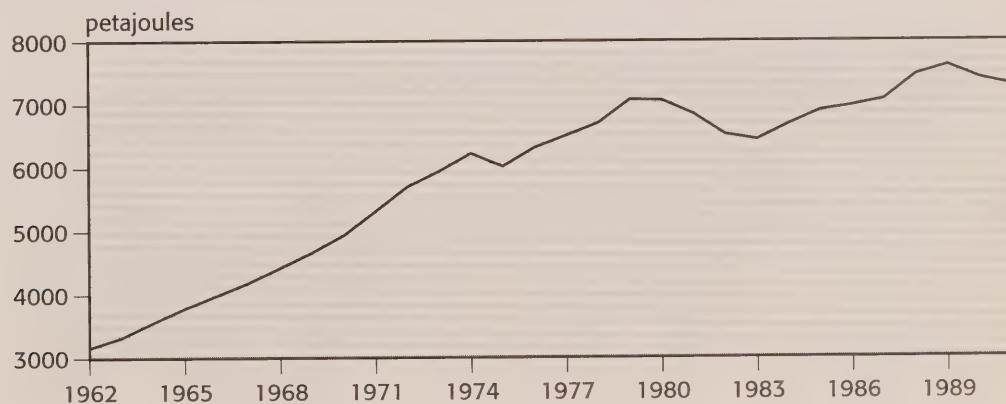
improvements. Government policy, motivated by concerns for security of energy supply and economic performance, enhanced these efforts through the introduction of "off-oil" and energy conservation programs in the late 1970s and early 1980s (For further details, see Annex I to this chapter).

The immediate impact of higher energy prices and government policy measures was felt through changes in consumer behaviour such as lowering thermostats and driving fewer kilometres. The full impact on energy consumption was not realized for a number of years because complete adjustment required changes in the capital stock; for example, the purchase and/or construction of more energy efficient equipment and buildings. Over the early 1980s, energy demand declined as efficiency improvements became increasingly evident. Following the recession of 1981-82 energy demand growth resumed but, despite a sharp drop in oil prices, its rate of growth was slower than any other period of economic expansion in recent history.

Demographic trends and weather were also contributing factors to the slow growth in energy demand in the 1980s. Population grew at similar rates in both decades but growth in household formation was much slower in the 1980s (1.9 percent) relative to the 1970s (3.2 percent). Based on heating degree days, the 1980s were, on average, five percent warmer than the 1970s and three percent warmer than normal. The net result of the combinantion of these various factors was that growth in energy demand slowed from 2.6 percent per year between 1971 and 1981 to 0.8 percent per year between 1981 and 1991.

Reflecting the movements in energy demand, energy intensity, defined as the amount of energy used to produce a given level of RDP, declined 0.7 percent per year in the 1970s but further declined 1.6 percent per year in the 1980s (Figure 4-2). Changes in energy intensity reflect not only changes in thermal efficiency of appliances and capital but also other factors such as shifts in the composition of industrial activity (because different production processes require quite different amounts of energy per unit of output) and changes in consumer preferences. Consequently, energy intensity is not always a precise measure of the efficiency of energy use. This distinction between efficiency and intensity is frequently ignored when international comparisons of energy use are made. For a number of reasons – distance, climate, the nature of the economy – Canada uses much more energy per unit of output than many other countries but this is not necessarily indicative of inefficiency of energy use in specific tasks.

4.3 ISSUES AND UNCERTAINTIES

In our analysis of energy demand we have concentrated on assessing the implications of two key uncertainties. The first relates to alternative paths for technological progress in reducing natural gas supply costs and the implications for the level of natural gas prices. To examine the implications of different natural gas supply costs on natural gas and total energy demand, two scenarios were developed: the Current Tech case with relatively high gas supply costs and the High Tech case with lower gas supply costs. These two scenarios also provide an indication of the sensitivity of energy demand to overall energy price changes.

FIGURE 4-2
Canadian End Use Energy Intensity[1]

1971 = 100

1   End-use energy demand per unit of real Gross Domestic Product
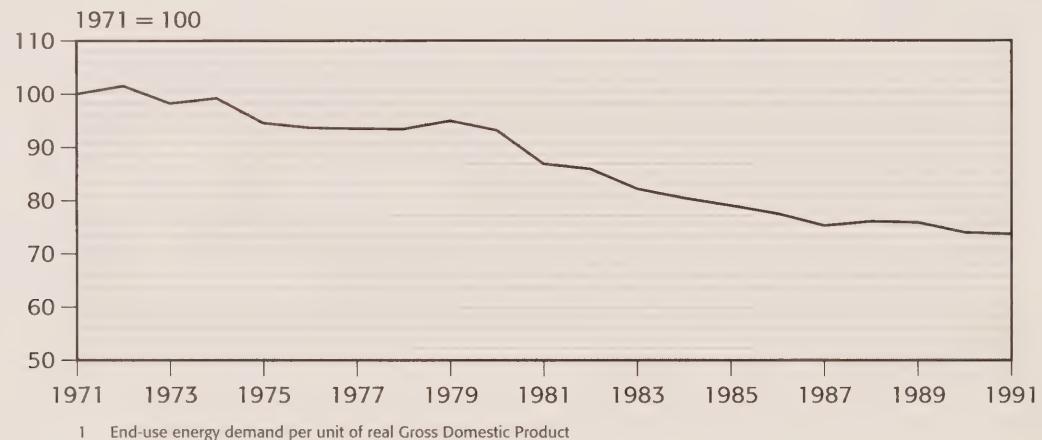
The second key uncertainty analyzed is with respect to the structure of the economy. Energy demand is sensitive to the distribution of growth among sectors in the economy. The industrial sector, which primarily produces goods, is roughly five times more energy intensive than the commercial sector. Therefore, shifts in the composition of economic activity from the commercial to the industrial sector result in increased energy use. A secondary impact of stronger growth in goods-producing industries is a higher demand for transportation services in order to move the increased volume of goods to market. Accordingly, the Alternative Macro case, which uses High Tech natural gas prices, was developed to explore the sensitivity of energy demand to a shift towards a more energy-intensive economic structure.

As noted above, energy demand growth is dependent upon a number of other factors. Although we recognize that variations in these factors will undoubtedly influence future outcomes, we have not attempted to incorporate an assessment of the possible variations in our analysis.

Our projections for macroeconomic growth focus on long-run sustainable economic growth as determined by changes in the labour force, the capital stock and productivity. We do not attempt to forecast the cyclical ups and downs of the economy.

History has demonstrated that energy prices can significantly impact long-term energy demand growth. High and volatile energy prices in the 1970s and early 1980s stimulated developments that led to the efficient use of energy. In this report, it is assumed that energy prices will be generally more stable than they have been over the last 20 years. The relative prices of energy commodities are also important in that they influence the relative shares of the various fuels. Energy consumers usually have some flexibility to switch between various fuels in response to relative price changes. Finally, we have taken an unchanged policy approach to the analysis through this report. We have not speculated on possible future policy initiatives.

4.4 TOTAL END USE ENERGY DEMAND: OVERVIEW OF THE PROJECTIONS

In all cases analyzed, growth in end use energy demand over the projection period is similar to, or higher than, the energy demand rates of growth observed in the 1970s and more than double the rate of increase observed over the 1980s. This is a consequence of the joint effects of a number of assumptions and factors:

- The effect of the large price increases of the 1970s and early 1980s on restraining growth in energy consumption is weakening, in part, because the replacement of the old stock of appliances and equipment with new, more energy-efficient equipment is largely completed.

- All of our price projections imply moderate rates of increase at the burner tip.

- The structure of economic growth in our projections is such that energy-intensive goods-producing industries grow more rapidly in all cases than they did in the past decade.

- There is no strong additional price or policy incentive to improve the efficiency with which energy is used.

In the Current Technology case, energy demand grows 1.5 percent per year over the projection period reaching 9 872 petajoules by 2010. In the High Technology case, characterized by significantly lower growth in natural gas prices, energy demand growth accelerates to 1.7 percent per year and reaches 10 297 petajoules by 2010. Energy demand growth is highest in the Alternative Macro case at 2 percent per year, reaching 10 854 petajoules in 2010.

Electricity continues to capture additional market share in all three cases. Natural gas loses market share in the Current Tech (CT) case but gains share in both the High Tech (HT) and Alternative Macro (Alt Macro) cases generally at the expense of oil products in sectors other than transportation. The shares of other energy commodities, such as renewables, petroleum products used in transportation and other fuels, generally remain near their 1991 values (Figure 4-3).

4.5 END USE BY SECTOR

4.5.1 Residential Sector

Energy demand in the residential sector is comprised of energy consumption by all households in their residential dwellings. Dwelling types include single houses, semi-detached houses, apartments, row townhouses, condominiums and mobile homes. The residential sector also includes energy used to operate farm equipment but it does not include gasoline used for household-owned vehicles.[1]

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1 Gasoline demand is included in the road transportation sector.

The residential energy demand share of total end use energy demand fell slightly from 22.6 percent in 1971 to 19.4 percent in 1991, largely reflecting rapid energy efficiency improvements and energy conservation measures undertaken by households.

In 1991, 64 percent of energy consumption in the sector was for space heating, 13 percent for water heating, 15 percent for lighting and appliances (refrigerators, microwaves, televisions, etc.), 7 percent for farm energy, and the remaining one percent for space

FIGURE 4-3
End Use Energy Demand by Fuel – Canada
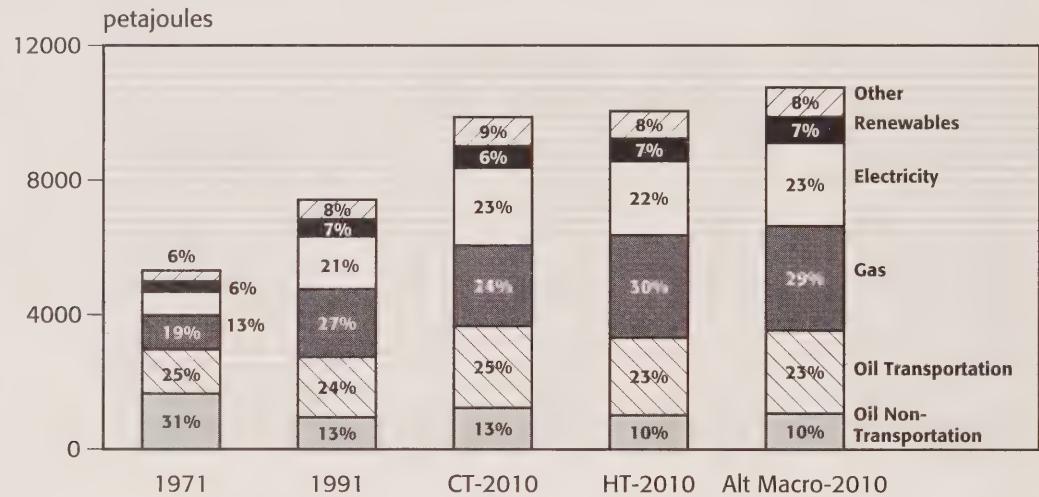
FIGURE 4-4
Residential Energy Demand
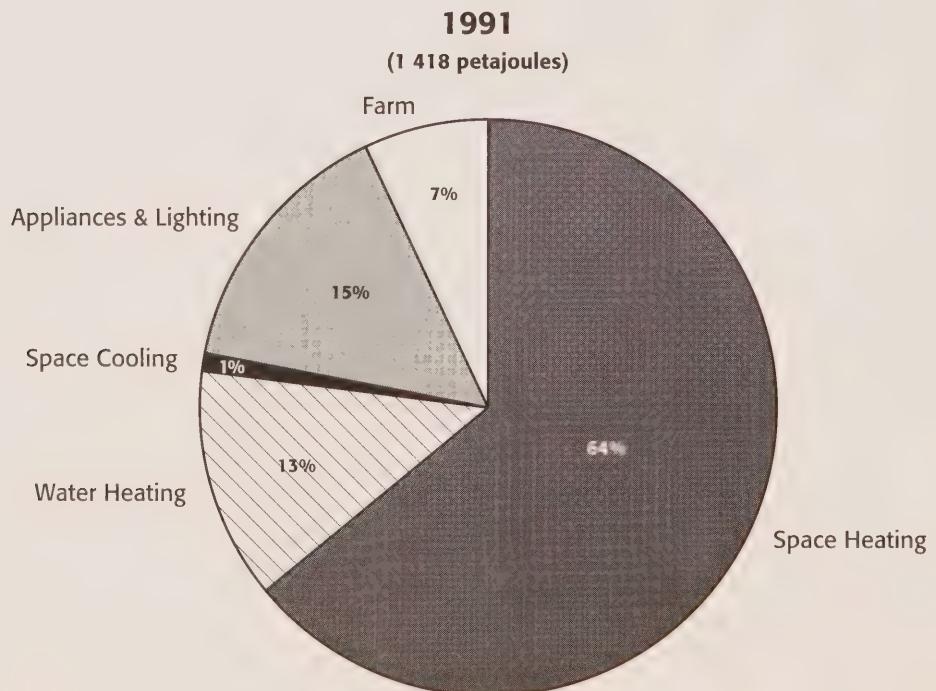
cooling. Naturally, end use shares vary by region. For example, British Columbia, despite its much larger population, uses less energy for space heating than Alberta reflecting the region's warmer winter weather.

4.5.1.1 Determinants of Residential Energy Demand

In the short run, residential energy demand is more sensitive to weather fluctuations than to most other determinants, including energy prices and household income changes. When the temperature is colder than normal, more energy is required for space heating, regardless of price or income. Figure 4-5 displays the relationship between residential energy demand per household, weather and average residential energy prices. Weather is represented by normalized heating degree days, where a value greater than one indicates colder-than-normal weather and a value less than one indicates warmer-than-normal weather conditions. Short-term fluctuations in energy demand match fluctuations in weather.

In the long term, residential energy demand is also influenced by the number of households, the number of persons per household, household personal disposable income, energy prices, and consumer attitudes and preferences.

As the number of households increases, more energy is used for space heating, water heating, lighting, and appliances. When the number of persons in a household declines, less energy is required for showers and electrical equipment. During the 1970s and the 1980s, the number of households grew at an average annual rate of 3.2 percent and 2.0 percent, respectively. In 1993, there were slightly more than ten million households in Canada. Persons per household fell steadily from 3.6 in 1971 to 2.8 in 1991. The net effect was an increase in energy demand in the residential sector.

The size of residential dwellings, which can be roughly measured by the number of rooms per household, influences energy use for space heating and

FIGURE 4-5
Residential Energy Demand per Household vs. Normalized Heating Degree Days and Average Residential Energy Prices
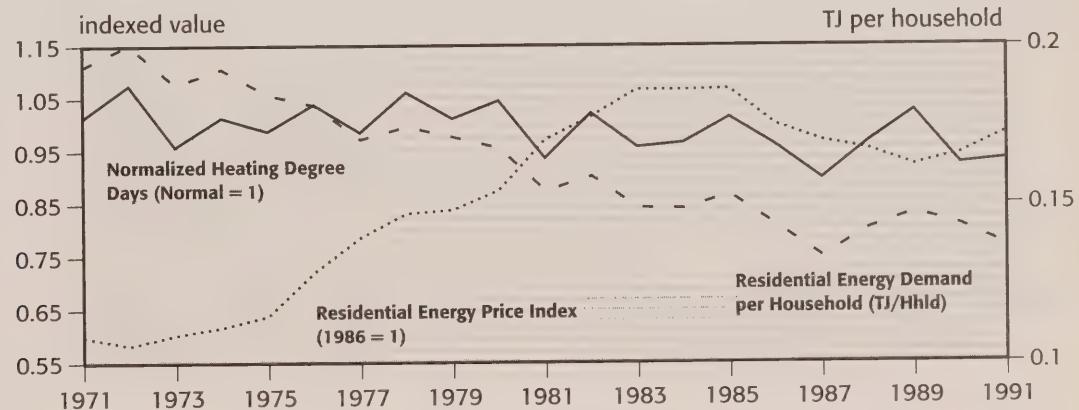
TABLE 4-1
Persons per Household and Rooms per Dwelling in Canada
(1971-1993)

Percentage of Households with:	1971	1975	1978	1983	1988	1993	AAGR (%)
1 – 3 Rooms per Dwelling	12.9	13.9	13.2	13.1	12.6	11.5	-0.5
4 – 6 Rooms per Dwelling	63.9	61.9	60.1	56.7	52.9	52.6	-0.9
7 or more Rooms per Dwelling	23.4	24.1	26.7	30.3	34.5	35.8	2.0
Number of Persons per Household	**3.6**	**3.3**	**3.1**	**2.9**	**2.8**	**2.7**	**-1.3**

cooling: the larger the dwelling, the larger the space heating and cooling requirements. The average size of homes in Canada has been growing steadily. The proportion of dwellings with seven or more rooms grew from 23.4 percent in 1971 to 35.8 percent in 1993.

Personal disposable income per household grew at an average annual rate of 2.5 percent over the 1970s, but growth slowed to 0.7 percent during the 1980s. With rising incomes, more households purchased new home appliances such as televisions, VCRs, dishwashers, clothes dryers and stereos. Higher incomes also allowed the purchase of larger homes.

Residential energy demand responds to changes in energy prices with a long lag. This is illustrated by the reduction in energy consumption per household and changes in energy prices shown in Figure 4-5.

Changes in consumer attitudes/tastes can have profound effects on long term trends in residential energy demand. During the 1970s, and more prominently during the 1980s, the stock of electrical household equipment and appliances increased, in part because of increased female participation in the labour force. The stock of time-saving appliances, such as dishwashers, clothes dryers and microwaves, grew rapidly. The percentage of households with dishwashers (i.e., the dishwasher penetration rate) rose by approximately 3 percent per year between 1983 and 1993. Microwaves showed the most rapid growth, as the number of households with microwaves grew by 20 percent per year over the same period. The availability of and demand for new and sophisticated equipment, such as home computers and VCRs, also increased the stock of electricity-using equipment in the residential sector.

TABLE 4-2
Penetration Rates of Major Household Appliances in Canada

Percentage of Households with:		1973	1978	1983	1988	1990	1992	1993
Refrigerators:	One	n/a	n/a	84.2	80.8	80.8	80.4	79.9
	More than one	n/a	n/a	15.5	18.8	18.7	19.0	19.9
Freezers		n/a	47.2	54.9	56.9	57.6	57.9	58.7
Electric Stoves		81.7	87.9	91.1	93.5	93.8	94.2	93.9
Dishwashers		n/a	23.9	33.9	41.3	42.0	44.2	45.2
Clothes Washers		n/a	76.3	76.4	77.0	78.6	78.6	79.3
Clothes Dryers		n/a	59.5	66.1	71.0	73.4	74.0	75.1
Microwaves		n/a	4.7	12.5	53.8	68.2	76.0	79.1

TABLE 4-3
Penetration Rates of Household Equipment in Canada

Percentage of Households With:		1983	1988	1991	1992	1993
Radios:	Total	98.8	98.7	98.9	98.8	98.8
	One	23.6	21.3	21.7	21.8	21.6
	More than one	75.2	77.4	77.2	77.0	77.2
Colour TVs:	Total	87.1	95.1	97.2	97.5	97.8
	One	71.4	62.5	56.6	54.8	51.7
	More than one	15.7	32.6	40.6	42.7	46.1
VCRs:	Total	6.4	52.0	68.6	73.8	77.3
	One	-	-	61.1	64.0	64.4
	More than one	-	-	7.5	9.8	12.9
Cassette or Tape Recorders		54.2	69.9	72.7	72.8	74.0
CD Players		-	7.9	20.9	26.9	33.2
Home Computers		-	12.6	18.6	20.0	23.3

4.5.1.2 Trends in Energy Intensity

Energy use per household (i.e., energy intensity) declined by approximately 40 percent between 1971 and 1991. This decline was the net result of energy efficiency improvements and other factors, some offsetting, such as an increase in the average size of homes.

Improvements in the energy efficiency of furnaces and water heating equipment have led to decreases in the amount of energy required for space and water heating. Government programs and new building codes led to improvements in home insulation, which also reduced space heating requirements. As reflected in Table 4-4, appliance efficiencies have improved significantly over the past ten years. On average, new refrigerators use 25 percent less electricity than those built in 1981.

A number of other factors, unrelated to energy efficiency trends, have also influenced the energy intensity of the residential sector. Although the decrease in the number of persons per household reduced energy use per household for showers and appliances, the steady increase in the average size of residential dwellings has increased space heating requirements per household.

The rapid increase in the penetration of new electronic appliances and equipment (Tables 4-2 and 4-3) increased energy use per household. Further, consumer tastes have moved towards "bigger and better" equipment and appliances, such as wide-screen TVs and refrigerators with built-in ice-makers; these generally use more energy than basic models.

Behavioural changes among household members have also resulted in an increase in energy consumption. In the 1960s and 1970s, it was still common for family members to gather in a single room and engage in the same entertainment activity. Today, family members typically scatter into separate rooms and entertain themselves individually. This results in a greater use of lighting and electronic equipment.

4.5.1.3 Government and Utility Sponsored Programs

Government and utility sponsored programs and government-legislated standards for household energy-using devices have reduced energy consumption and encouraged fuel-switching, although with varying effectiveness.[2]

In summary, the growing number of households, increasing personal disposable income and changes such as the demand for larger homes has led to increasing residential energy demand. This rate of growth was reduced in the 1980s due to higher energy prices, and the resultant emphasis on more efficient use of energy and government-sponsored programs to reduce energy use. The net effect was that residential energy use grew from 1 200 petajoules in 1971 to 1 418 petajoules in 1991.

4.5.1.4 Residential Energy Demand by Fuel Type

The three main fuels used in the residential sector are natural gas, electricity, and light fuel oil. These accounted for 87 percent of total residential sector energy demand in 1991. Other fuels used in the residential sector include propane, wood, solar, kerosene and diesel fuel oil (DFO). Many mobil homes use propane for hot water and space heating. Wood is also a common fuel for home heating; however, it is often used as a secondary fuel source. Due to their large capital and maintenance costs, active solar heating systems are rarely used for residential space and water heating.

Fuel shares respond to relative fuel prices as households seek to minimize expenditures on energy. However, there are limitations on the degree of substitutability between fuels. For example, electricity is the only fuel that can be used to operate electronic

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2   For further details, see Annex I to this chapter.

TABLE 4-4

Average Annual Electricity Consumption by Major Appliances in Canada

(kW.h per year)

(1981-1991)

	1981	1986	1991	AAGR (%)
Refrigerators	1 500	1 344	1 128	-2.9
Freezers	756	684	636	-1.7
Cooking Ranges	828	828	828	0.0
Clothes Washers	144	120	120	-1.8
Clothes Dryers	1 164	1 104	1 104	-0.5
Dishwashers	360	324	312	-1.4

equipment and is by far the most convenient energy form used for lighting.

Due to its low price relative to other fuels, natural gas has become the fuel of choice for space and water heating in new housing in most regions of the country where it is available. Natural gas has also gained recent popularity because of its perception as an "environmentally friendly" fuel. Demand for natural gas in the residential sector more than tripled between 1962 and 1991.

Light fuel oil use declined rapidly, especially during the 1980s, as a result of high oil prices, concerns

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FIGURE 4-6
Residential Energy Demand by Fuel

1991
(1 418 petajoules)

Renewables: 7%
Other: 1%
Oil: 18%
Electricity: 35%
Natural Gas: 39%
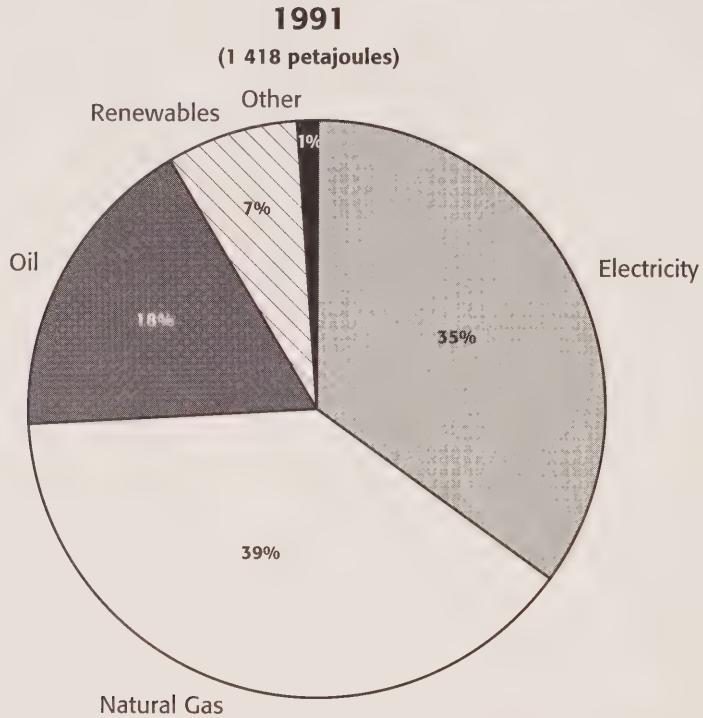
FIGURE 4-7
Real Residential Fuel Prices[1]

$1993 per gigajoule

Electricity
LFO
Natural Gas-CT
Natural Gas-HT

1971 1975 1979 1983 1987 1991 1995 1999 2003 2007
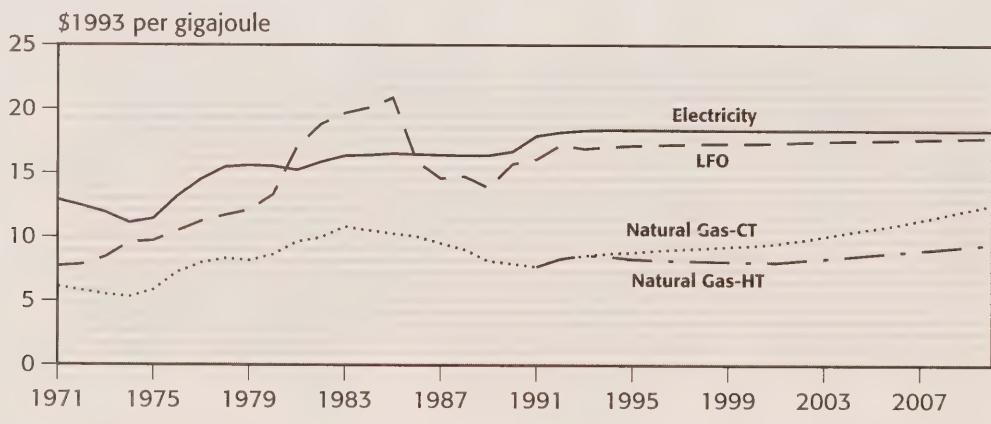
1 Efficiency - adjusted prices

about oil supply, and the federal government's COSP program. Residential oil demand declined by 5 percent per year on average between 1971 and 1991.

Electricity consumption increased steadily over the 1962 – 1991 period as the number of electricity-using appliances increased rapidly during this period. Increased electricity used for household appliances offset a reduction in the share of electricity used for space and water heating, resulting in a net increase in electricity demand.

The shares of other fuels used in the residential sector, such as wood, propane and coal, declined over the 1962 – 1991 period. These fuels are usually used in remote and/or rural regions where gas, oil, and electricity are economically unattractive relative to other fuels.

4.5.1.5 Projections

Growth in total residential sector energy demand is projected at slightly less than one percent per year on average over the projection period in all three cases analyzed. Figure 4-8 displays actual and projected changes in the main determinants of residential energy demand. Although growth in personal disposable incomes and rates of household formation are assumed to be lower over the projection period than in the past two decades, the rate of increase in residential energy prices is also projected to be lower. The expected net effect is to roughly maintain past energy demand growth.

Average energy and gas prices are lower in the High Tech case than in the Current Tech case. Consequently, residential energy demand increases by 0.9 percent per year in the High Tech case versus 0.7 percent in the Current Tech case. The Alternative Macro case features lower growth in average personal disposable income per household and the energy prices of the High Tech case. The net result is residential sector energy demand growth of 0.8 percent per year, mid-way between the Current Tech and High Tech cases.

Although most government sponsored programs have ended, efficiency improvements are assumed to continue. Energy use per household is projected to continue to decline at approximately 0.9 percent per year in the Current Tech case. In the High Tech case, energy intensity declines 0.7 percent per year as lower average energy prices lengthen the payback period from investments in energy efficiency improvements. Residential energy intensity declines more rapidly in the Alternative Macro case (0.8 percent per year), than in the High Technology case reflecting lower growth in households incomes.

The decline in energy intensity in all three cases is the result of many factors:

* Penetration rates of higher efficiency equipment for space and water heating are assumed to increase over the projection period.

FIGURE 4-8
Main Determinants of Residential Energy Demand
(Average Annual Growth Rates – Percent)
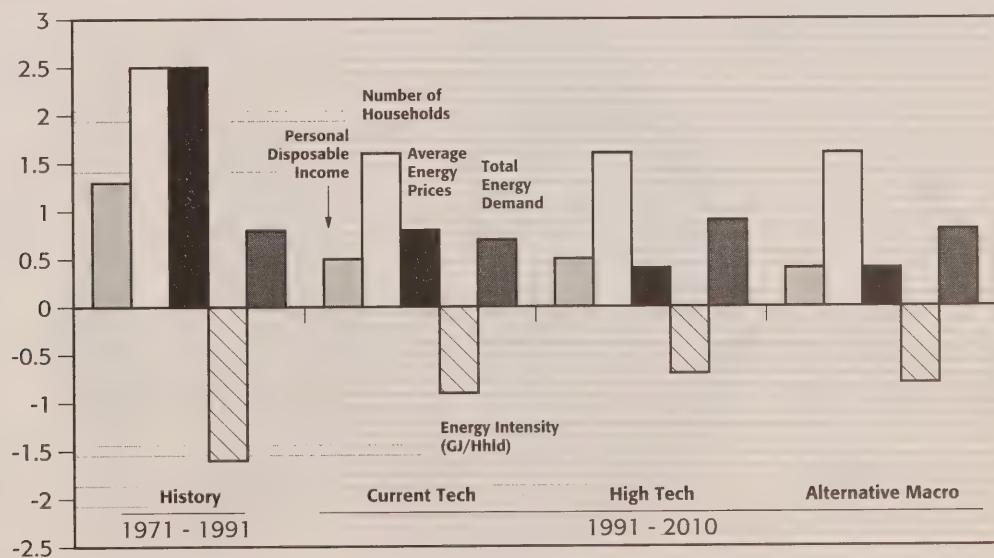
- The average number of persons per household is assumed to continue to decline. This results in a decrease in energy use per household for appliances and hot water.

- The thermal efficiency of new residential construction is higher than that of the current housing stock leading to an increase in the average thermal efficiency of the total housing stock.

- Further improvements in the energy efficiency of household appliances and equipment will also decrease energy use per household.

The impact of these factors on energy intensity is somewhat offset by an increase in the penetration rates of household appliances and equipment and an increase in the average size of residential dwellings.

The share of natural gas in residential sector energy demand continues to increase, even in the Current Tech case, although the increase is more pronounced with the lower gas prices of the High Tech and Alternative Macro cases (Figure 4-9). Most of the increase in the natural gas share occurs at the expense of light fuel oil used for space and water heating. It is significantly cheaper to convert to a natural gas heating system from an oil heating system than from electric baseboard heating.

Electricity demand is projected to increase at approximately 1.5 percent per year in each case. This is largely the result of increasing penetration rates of electronic household equipment and appliances.

Electricity demand in the High Tech case is somewhat higher, reflecting the fact that average space heating bills as a result of lower natural gas prices are much lower in the High Tech case. A conservative estimate of the savings from these lower gas prices is approximately $9.2 billion in 1986 dollars over the projection period. Some of these monetary savings would be used by households to purchase new household appliances and equipment, with an associated increase in electricity consumption. Appliance efficiency improvements are assumed to continue, but households use more and larger appliances. Continued application of DSM programs slightly dampens growth in electricity demand in both cases.

Electricity is assumed to remain the main fuel source for space and water heating in Québec as natural gas and oil prices rise in that province relative to electricity prices. In fact, real efficiency-adjusted natural gas prices in Québec almost reach the level of electricity prices by 2010 in the Current Tech case.

In summary, we expect growth in residential sector energy demand to continue over the projection period. This is based on a general view that growing personal disposable income, combined with relatively stable end use prices and the introduction of new energy using household products, will lead to growing demand for energy. Demand growth is partially muted by ongoing improvements in energy efficiency. The rate of growth is modestly affected by varying the assumptions with respect to natural gas prices or, in the Alternative Macro case, with respect to the structure of the economy.

FIGURE 4-9
Residential Energy Demand by Fuel
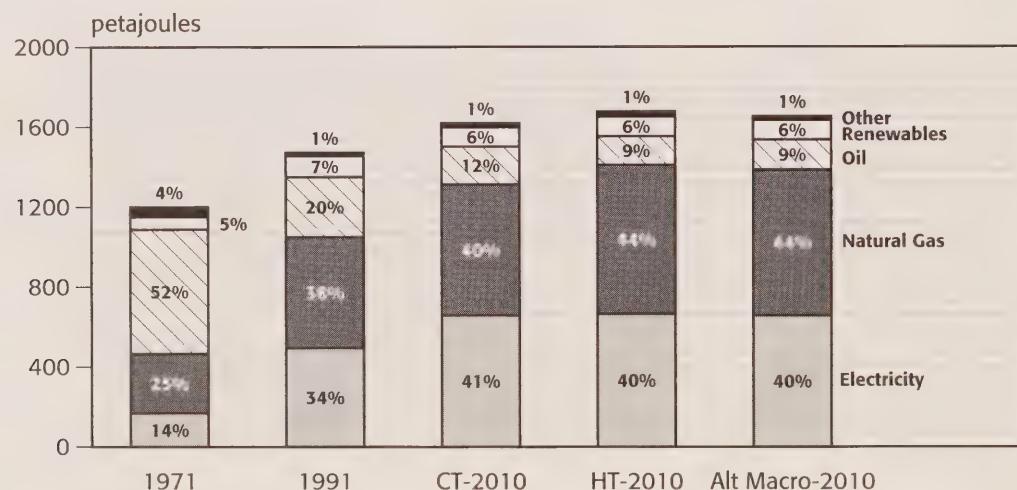
4.5.2 Commercial Sector

The commercial sector is comprised of all service-producing industries and institutions, such as banks, hospitals, schools, retail stores, hotels, restaurants, and government administration. This sector also includes street lighting. Under Statistics Canada definitions and for the purpose of our analysis, DFO used by non-government commercial industries is excluded from the commercial sector, while DFO used in the government sector is included.[3]

Commercial sector energy demand as a proportion of total energy demand fell from 12.5 percent in 1971 to 11.7 percent in 1981 but then increased to 12.4 percent in 1991. Slightly more than half of all energy consumed in the commercial sector (55 percent) was used for space heating in 1991. Of the remaining 45 percent, 14 percent was used for lighting, 11 percent for ventilation, 8 percent for equipment, 6 percent for water heating and 6 percent for space cooling (Figure 4-10).

4.5.2.1 Determinants of Commercial Energy Demand

As with the residential sector, commercial sector energy demand is most sensitive to variations in the weather in the short run because of its large space conditioning (heating and cooling) component. In the longer run, commercial energy demand responds to changes in commercial RDP, energy prices, long-term technological developments and changes in business practises.

Commercial energy demand grew approximately 3 percent per year, on average, between 1973 and 1991. The Canadian economy became more service-oriented during the 1960s, 1970s, and 1980s and the commercial sector grew rapidly – commercial floor space almost doubled in the 1970s.

Higher penetration rates of electrical and other equipment used in offices and institutions also added to growth in commercial energy demand and energy use for space cooling increased as new commercial buildings in most regions of the country, especially Ontario and Québec, were constructed with air cooling systems.

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3 Since DFO used by non-government commercial industries is used primarily for transportation, it is accounted for in the transportation sector. Diesel fuel oil consumed in the government sector is not excluded because it is used for both transportation and non-transportation purposes, such as the generation of electricity by large public institutions. Data limitations make it is difficult to estimate the transportation component.

FIGURE 4-10
Commercial Energy Demand

1991
(903 petajoules)

Space Cooling — 6%
Equipment — 8%
Ventilation — 11%
Lighting — 14%
Water Heating — 6%
Space Heating — 55%
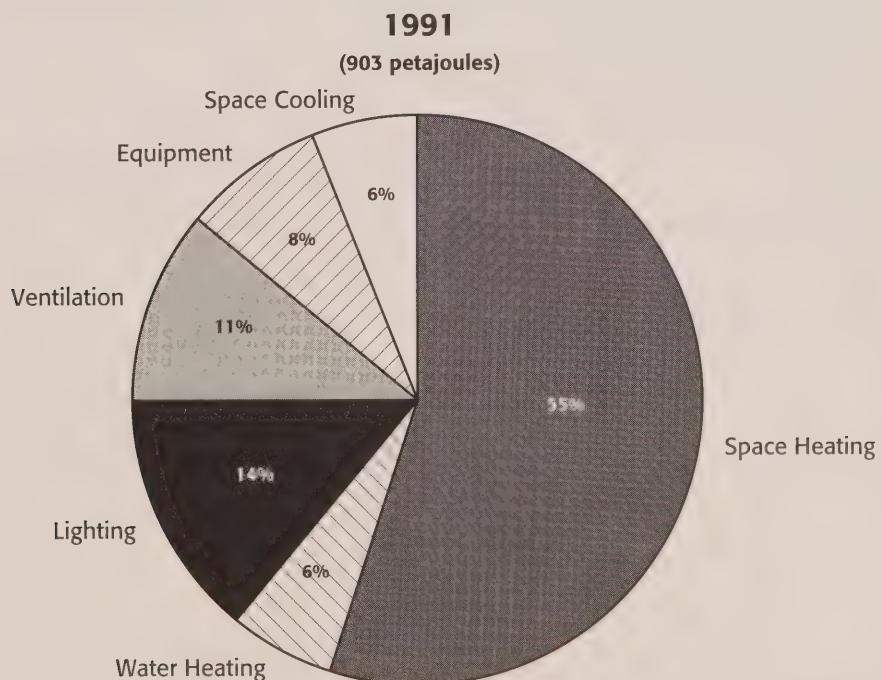
Commercial energy demand responds to changes in energy prices with a long lag. In the short run, commercial energy demand is relatively insensitive to price changes since commercial buildings require a minimum amount of energy for space conditioning, water heating, lighting, ventilation and to operate equipment.

Technological developments have dramatically altered business practices. Use of electricity-using equipment, such as computers, laser printers, photocopiers, and fax machines has increased rapidly. Many processes in the workplace that were previously performed manually have become automated. Although a few of the changes in business practices have resulted in decreased energy demand, the net effect has been to increase demand.

4.5.2.2 Trends in Energy Intensity

Several indicators of energy intensity are available. Although the standard measure of energy intensity in the commercial sector has been energy use per unit of RDP, a more appropriate measure, in our opinion, is energy use per unit of floor space. Unfortunately, data for commercial floor space are only available since 1980 and, therefore, long-term comparisons of historical trends in energy intensity cannot be made using this measure. Further, these data are only rough estimates. Figure 4-11 displays both energy intensity measures for Canada, while Table 4-5 shows average annual growth rates for commercial floor space by building type and by region over the 1981 to 1991 period.

Energy use per dollar of commercial RDP declined by approximately 1.6 percent per year between 1973 and 1991, while energy demand per square metre of floor space declined 3 percent per year on average

between 1981 and 1991. The average new office building uses approximately 700 MJ/m² (or 37%) less energy than an office building constructed in 1980 and 400 MJ/m² (or 25%) less than one constructed in 1985.[4] New buildings are constructed with better insulation and reflective glass and consequently require less energy per square metre both for space heating and cooling. In addition, they tend to be built with large window areas which, combined with more energy-efficient lighting equipment, has reduced the amount of electricity required for interior lighting. There were also major improvements in the efficiency of street lighting during the 1980s. Offsetting these energy-efficiency improvements was the introduction of computers, photocopiers, laser printers and fax machines which increased the "plug load".

4.5.2.3 Government and Utility Sponsored Programs

Government and utility sponsored programs and government-legislated standards for commercial buildings and energy-using equipment reduced commercial energy consumption during the 1970 to 1991 period.[5]

4.5.2.4 Commercial Energy Demand by Fuel Type

Over the historical period, there has been a steady increase in electricity use, a decline in light fuel oil consumption and a fairly rapid increase in natural gas

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4   *The Economically Attractive Potential for Energy Efficiency Gains in Canada: Case Study #3 – Commercial*, prepared by Marbek Resource Consultants for Energy, Mines and Resources, May 1991.

5   For further details, see Annex 1 to this Chapter.

FIGURE 4-11
Commercial Energy Intensity
1991 = 1.0
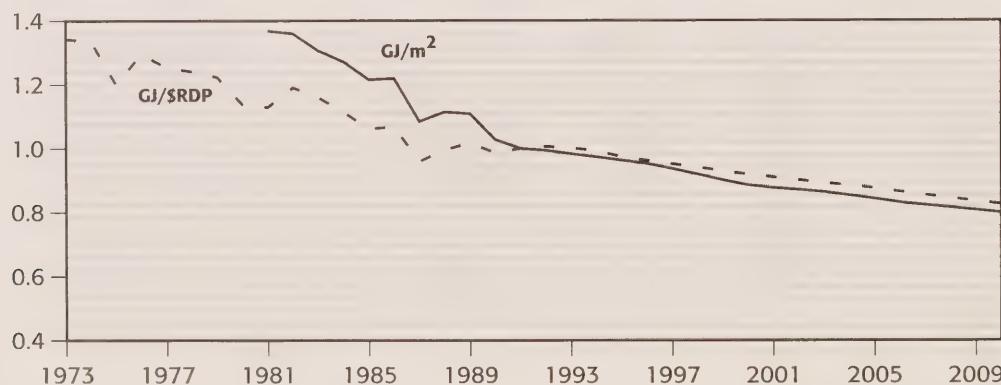
demand. However, some regional differences exist as a result of differences in relative prices, market structure, fuel availability and regional government programs.

Natural gas and electricity are the two main fuels used in the commercial sector. They accounted for almost 90 percent of total energy demand in 1991, a significant increase from their 1962 share of 58 percent. Light fuel oil accounted for about 5 percent while heavy fuel oil (HFO), diesel fuel oil and LPG accounted for the remainder (Figure 4-12).

In the long run, fuel shares of commercial energy demand are primarily determined by the relative prices of these fuels, technological changes, government and utility sponsored fuel-switching incentive programs, and changes in energy efficiency standards. Natural gas is not available in Atlantic Canada and in some communities in other regions, and therefore is not an option for these consumers.

Since the price of natural gas[6] is, on average, approximately one fifth the price of electricity, it has become the fuel of choice for space and water heating in most new commercial buildings.[7] Nevertheless, increasing penetration and utilization rates of electrical and electronic equipment in the commercial sector led to an average growth in electricity demand of 4 percent per year between 1980 and 1991.

Consumption of heavy fuel oil in the commercial sector fell rapidly – by approximately 14 percent per year – between 1971 and 1991. This decline reflected increased availability and use of natural gas in Ontario and Québec and the effects of off-oil programs.

4.5.2.5 Projections

In all three cases, total commercial energy demand increases at about the same rate (1.3 percent per year on average) over the projection period as it did between 1973 and 1991. Although commercial RDP is assumed to grow at a slower rate than in the recent past, energy prices also rise much more slowly.

Since the Canadian economy is emerging from a recession, the first part of the projection period will be heavily influenced by cyclical factors. Typically during a recession, commercial energy consumption declines or at least increases less rapidly, as both commercial office space occupancy rates and office equipment use decline. Nevertheless, buildings must be heated to a certain standard, whether occupied or not. Consequently, energy intensity measured as consumption per dollar of RDP increases during a recession. During the early recovery period utilization of commercial floor space increases, energy demand grows more slowly than commercial RDP, and energy intensity tends to decline.

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6 Efficiency adjusted gas price.

7 The Marbek report cited above indicated that accurate data regarding the share of natural gas in new commercial construction was difficult to obtain. However, they provided an estimate based on discussions with engineering firms and utility personnel. With the exception of Ontario, they expect natural gas to continue to dominate the office space heating market in regions where gas is readily available. Based on their discussions with Ontario Hydro and some Ontario engineering firms, Marbek Consultants anticipate that electricity will serve some of the new office space heating market in Ontario, but natural gas will continue to dominate.

TABLE 4-5

Commercial Floor Space by Building Type: 1981 – 1991

(Average Annual Growth Rates – Percent)

	Warehouses	Retail	Hotel and Restaurants	Office Buildings	Educational Buildings	Other	Total of All Building Types
Atlantic	0.6	4.1	7.2	6.8	2.7	3.2	3.9
Québec	2.5	3.2	6.1	5.9	1.3	2.4	3.5
Ontario	3.0	5.4	7.0	8.1	1.5	3.9	5.1
Manitoba	0.0	3.0	1.6	4.0	1.6	4.0	2.5
Sask.	2.0	2.3	4.1	4.4	2.5	4.1	3.3
Alberta	1.8	6.4	2.3	5.7	2.7	5.6	4.6
BC & Territories	2.1	7.0	5.8	6.3	2.3	5.8	5.3
Canada	**2.3**	**4.9**	**5.5**	**6.8**	**1.9**	**3.9**	**4.4**

Source: *Historical Estimates of Commercial Floor Space in Canada by Building Type*, Informetrica Ltd., 1993

A further consequence of high vacancy rates during recessions is that the existence of vacant office space dampens construction of new and generally more efficient commercial floor space. Improvements in the average energy-efficiency of the commercial floor space stock are delayed until construction activity picks up later in the recovery period.

Although government-sponsored programs have ended and price increases are modest, efficiency improvements are assumed to continue, partly due to DSM. Energy use per commercial RDP dollar is projected to continue to decline by approximately one percent per year until 2010 in the Current Tech case. In both the High Tech and Alternative Macro cases, energy intensity declines marginally less rapidly at a rate of 0.9 percent per year, on average, over the projection period, due to lower energy prices in both cases and a slower turnover in the stock of commercial floor space in the Alternative Macro case (Figure 4-13).

Commercial floor space is projected to increase by approximately 2.5 percent per year in Canada. Energy intensity, when measured as energy use per square metre of floor space declines at approximately 1.2 percent per year between 1991 and 2010 (Figure 4-11).

Most of the new commercial floor space construction is assumed to be in office buildings. Office floor space increases from 30 percent of total floor space in 1991 to 36 percent by 2010, while the share of warehouses, retail and educational buildings declines.

In general, natural gas continues to capture the largest part of the commercial space heating market as it remains the cheapest fuel in all regions where it is available (Figure 4-14). Growth in natural gas demand is slowed by improvements in the average energy efficiency of the stock of commercial buildings, achieved mainly through building design and furnace efficiency improvements. In the Current Tech case, the share of natural gas increases in the early part of the projection period when the price of gas rises at about the same rate as electricity and light fuel oil prices, but declines by the end of the projection period reflecting relatively rapid increases in gas prices after 1995. In the High Tech and Alternative Macro cases, natural gas becomes relatively less expensive and natural gas captures an increasing share of the space heating market.

Approximately one-third of energy use in the commercial sector is electricity that is non-substitutable (i.e., lighting, ventilation, and "plug-ins"). With the

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FIGURE 4-12
Commercial Energy Demand by Fuel

1991
(903 petajoules)

Other

Electricity

Natural Gas

4%

45%

5%

2%

LPG

Light Fuel Oil
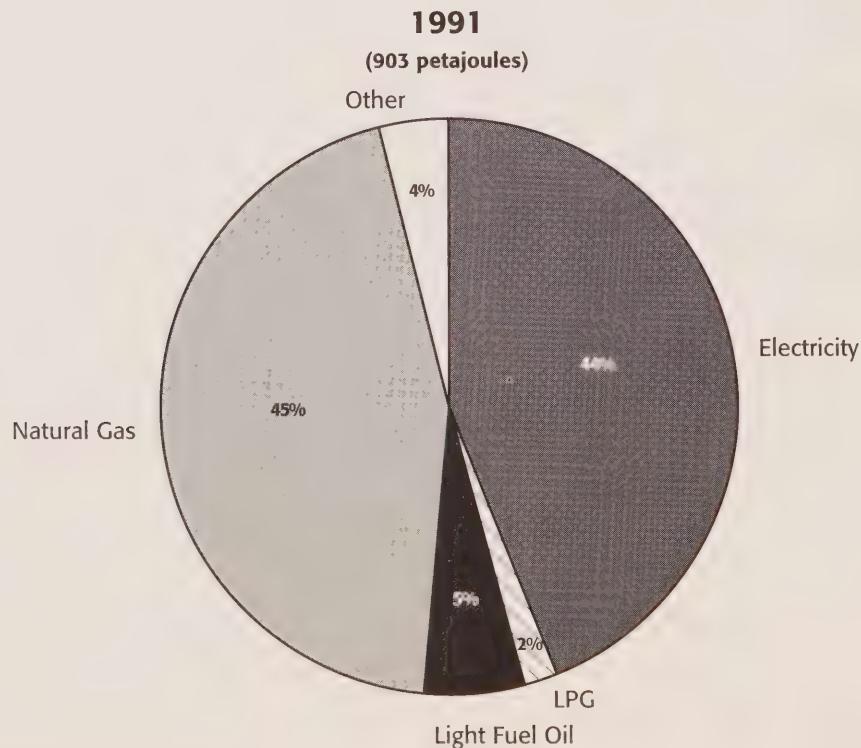
moderately high level of commercial building construction, assumed electricity demand for lighting and ventilation increases. The share of electricity increases in all three cases as a result of continued increases in the penetration and utilization rates of office equipment, increasing penetration rates of space cooling systems and the additional space cooling requirements resulting from the extra heat generated through the use of office equipment.

Since the price of natural gas remains low relative to electricity, electricity's share of the commercial space heating market declines. In regions where gas is not readily available or is not economical to use, electricity is expected to be the dominant fuel used for space heating.

The share of oil products in commercial sector energy demand continues to fall in all three cases. The already small share of light fuel oil consumption in commercial sector energy demand falls from

FIGURE 4-13

Main Determinants of Commercial Energy Demand

(Average Annual Growth Rates – Percent)
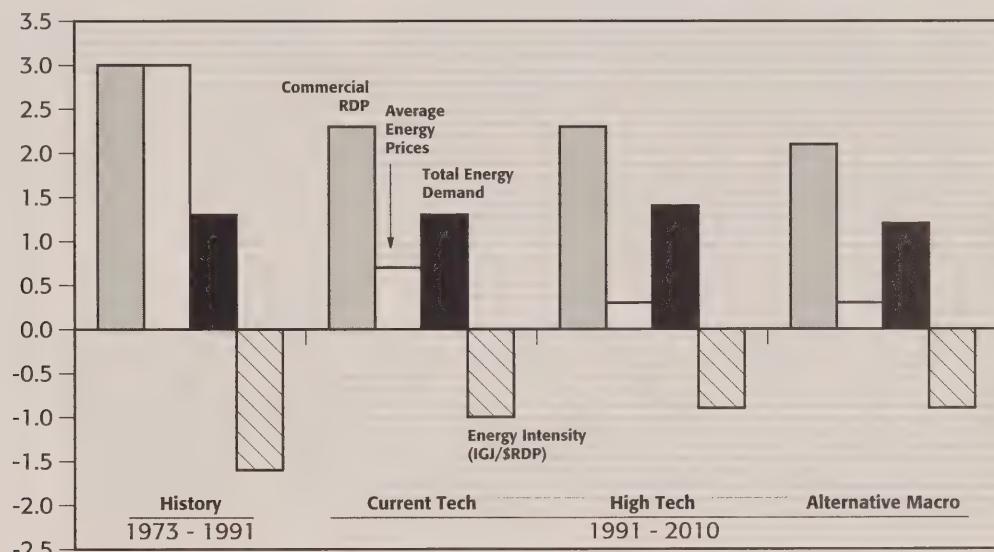
FIGURE 4-14

Real Commercial Fuel Prices[1]
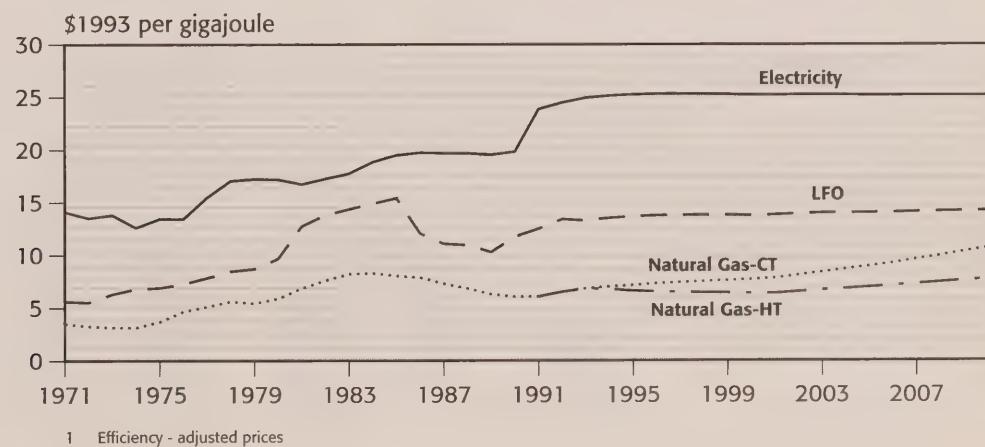
1 Efficiency - adjusted prices

approximately 6 percent (or 51 petajoules) in 1991 to 4 percent (or 45 petajoules) in the Current Tech case and 2 percent (23 petajoules and 22 petajoules, respectively) in both the High Tech and Alternative Macro cases by 2010. The share of other oil products used in the commercial sector, such as diesel fuel oil, heavy fuel oil and LPGs, are also projected to decrease.

In summary, energy demand in the commercial sector is expected to show ongoing moderate growth under each of our scenarios of about 1.2 percent to 1.4 percent per year. The share of total end use energy demand accounted for by the commercial sector is expected to remain roughly constant at about 12 percent.

4.5.3   Industrial Sector

In our analysis, the industrial sector is disaggregated into seven subgroups of manufacturing industries – Pulp and Paper, Iron and Steel, Smelting and Refining, Cement, Petroleum Refining, Chemicals and Other Manufacturing – as well as Mining, Forestry, and Construction. Energy is used in industrial processes primarily to produce heat, generate steam, or as a source of motive power. However, some processes use energy in other ways, such as for electrolysis in aluminum production. Historically, the industrial sector has been highly energy intensive; it has consistently accounted for approximately one-third of total end use energy demand, the largest share of any sector. Despite the near constancy of its energy share, the industrial sector's share in total economic output has declined steadily from more than 40 percent in the late 1960s to less than 30 percent in 1991.

4.5.3.1 Determinants of Energy Demand

The primary determinants of industrial sector energy demand are the level of economic activity in each industry within the sector, energy prices, changes in capital intensity (capital-output ratio) and technological change. In our analysis, which examines industrial sector energy demand in aggregate, the first three of these factors are represented by, respectively, industrial RDP, average industrial energy prices and the level of the net manufacturing capital stock. Technological change is accounted for judgementally.

Figure 4-16 displays the evolution of industrial energy demand over the past 30 years.[8] The sensitivity of industrial sector energy demand to cyclical changes in economic activity is quite evident in the declines and subsequent recovery of energy demand during the recessions of 1974-75, 1981-82 and 1990-92. Overall, there has been a clear upward trend in industrial energy demand although its rate of growth has slowed since 1973. This has reflected both a slowing in the rate of growth in industrial RDP and decline in energy intensity, which occurred largely in response to energy price increases.

Energy intensity in the industrial sector is defined as the amount of energy required to produce one dollar of real output. Changes in total industrial sector energy intensity can reflect shifts in industry RDP shares as well as efficiency improvements in industrial processes and industrial equipment. Energy intensity is greatly affected by cyclical movements in economic activity, tending to

8   Data from 1962 to 1970 are based on NEB estimates.

FIGURE 4-15
Commercial Energy Demand by Fuel

petajoules

	1962	1971	1991	CT-2010	HT-2010	Alt Macro-2010	
Other	13%	1%	2%	2%	2%	2%	
Natural Gas	23%	30%	45%	43%	45%	45%	
Electricity	21%	23%	44%	48%	47%	46%	
Oil	43%	46%	9%	7%	6%	6%	
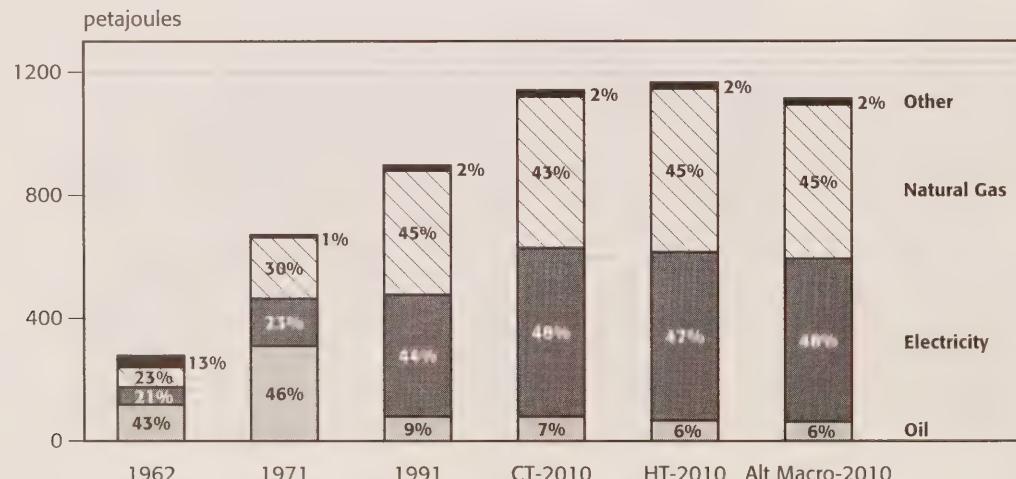
rise during cyclical downturns and to decline in the early stages of economic recovery. This reflects the fact that it can be costly and inefficient to shut down and restart some industrial processes even when economic activity is slack. The variability of industrial sector energy intensity is illustrated in Table 4-6 for the two most recent recessionary episodes and the 1980s recovery.[9]

Energy consumption by only a few industries, Pulp and Paper, Iron and Steel, Mining and Chemicals, make up the largest part of energy demand within the industrial sector. As shown in Table 4-7, the share of total industrial energy demand of these four industries has increased slightly from 60 percent in 1978 to 62 percent in 1991 while their share of total industrial RDP has declined from 30 percent to 26 percent.[10] Energy intensities for Pulp and Paper and Mining actually rose over this time period while overall energy intensities for the manufacturing and total industrial sector declined.[11]

4.5.3.2 Industrial Demand by Fuel Type

Fuel shares in the industrial sector are generally highly responsive to changes in relative prices because energy is often a major factor in the cost structure and therefore profitability of a firm. Inter-fuel substitution is

9   Recessions are defined in this context as the period from peak-to-trough in industrial RDP. The 1982-84 expansion was defined as the time period from the trough year to the year in which the pre-recession peak in industrial output was reached.

10   Presently, 1978 and 1991 are the first and last years respectively of data availability on an industry-by-industry basis.

11   Energy intensities for the pulp and paper and mining industries provide illustrations of the danger of using energy intensity as a proxy for energy efficiency. Within the pulp and paper industry, the growing use of hog fuel and pulping liquor, which have low efficiency factors, creates the appearance of declining energy efficiency. In the case of the mining sector, the historical period is dominated by the expansion of the oil and gas industry in western Canada.

FIGURE 4-16
Industrial Energy Demand
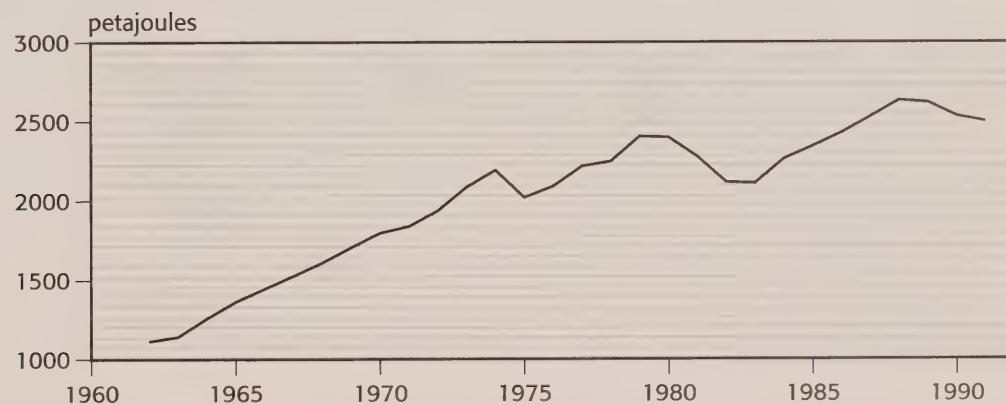
TABLE 4-6

Change in Industrial RDP, Energy Demand and Energy Intensity
(Average Annual Growth Rates – Percent)

	Industrial RDP	Energy Demand	Energy Intensity
Expansion			
1982-1984	13.7	6.9	-6.0
Contraction			
1981-1982	-8.8	-7.0	1.9
1990-1992	-7.7	-6.1	1.6

most important for uses involving the generation of heat, for example, in high temperature ovens and for boiler fuels. Fuel shares are also driven by the direction of change in the technology of fuel use and industrial processes[12] and structural changes in the nature of regulatory/environmental restrictions. Further, certain industries (the Pulp and Paper, Forestry and Iron and Steel industries) use fuels which are by-products of the production process; consumption of by-product fuel[13] is driven by availability.

The use of heavy fuel oil declined in the aftermath of the increase in oil prices in the 1970s and early 1980s, while the use of electricity and natural gas increased strongly. In addition to relative price increases, security of supply considerations and the increasing penetration of technologies that use electricity also acted to reduce the heavy fuel oil share (Figure 4-17, Table 4-8).[14]

The "other oil" category has not changed substantially; this category is largely composed of DFO used in the operation of heavy equipment. Natural gas,

12 For example, the growing market share of electricity has, to some extent, been a function of the growing share of technologies in industry that utilize electricity rather than as a result of changes in its relative price. However, the aluminum industry's concentration in Québec and B.C. is related to the relatively low price of electricity in these regions.

13 In the case of the Pulp and Paper and Forestry industries, on-site fuel is in the form of pulping liquor and hog fuel, while in the iron and steel industry, coke oven gas is a combustible gas that is a by-product of coke manufacturing for use in blast furnaces.

14 An example of a renewable fuel is wood wastes, or hog fuel, which is wood scrap and lumber rejects commonly used for fuel in the Pulp and Paper and Forestry industries. This scrap wood is generated during the production process and is typically burned for the heating of boilers or to generate heat for the drying of final products.

TABLE 4-7

Industrial RDP and Energy Shares for Energy Intensive Industries
(Percent)

Industry	RDP Share		Energy Share	
	1978	1991	1978	1991
Pulp and Paper	6.7	5.3	28.4	30.8
Iron and Steel	3.4	2.5	13.8	9.6
Mining	15.8	14.1	9.5	12.7
Chemicals	4.4	5.0	8.2	9.5
Other	69.7	73.1	40.1	37.4
Total	100.0	100.0	100.0	100.0

FIGURE 4-17
Industrial Energy Demand by Fuel
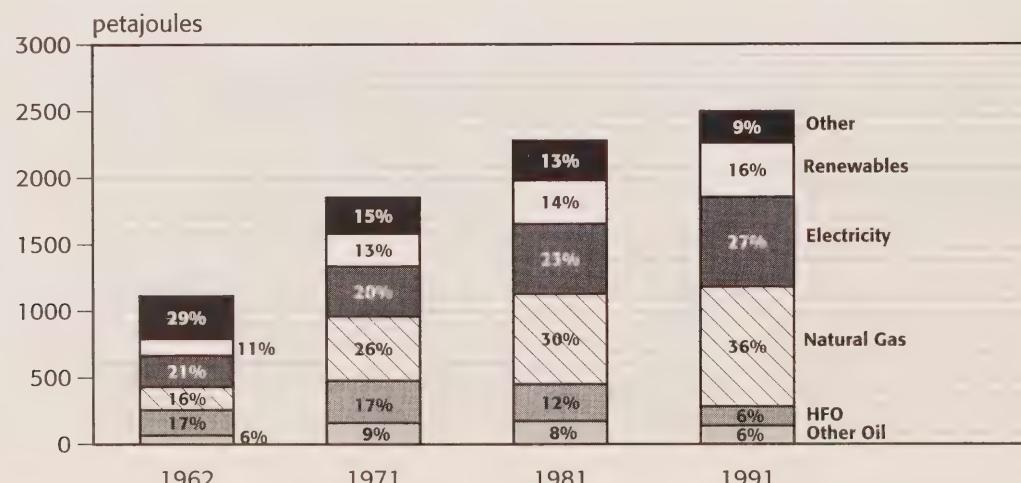
electricity and renewables all made strong gains in market share. The sharp drop in the "other" category from the 1960s to the early 1970s is a result of the substitution of natural gas for coal.[15]

4.5.3.3 Government and Utility Sponsored Programs

Inter-fuel substitution and fuel market shares in the industrial sector have been and will likely continue to be influenced by government and utility sponsored programs aimed at encouraging inter-fuel substitution or improvements in energy efficiency. A variety of government (mostly federal) initiatives, encouraging substitution away from oil and greater energy efficiency and conservation, emerged from the concern for security of supply following the oil price shocks of 1973-74 and 1979. Some utilities have also offered programs to encourage switching from oil to natural gas or electricity.

4.5.3.4 Projections

Industrial sector energy demand is projected to increase much more rapidly between 1991 and 2010 in all three cases analyzed than over the previous 20 years (Table 4-9). Overall, industrial demand increases from 2 506 petajoules in 1991 to 3 571 petajoules in the Current Tech case, 3 886 petajoules in the High Tech case and 4 481 petajoules in the Alternative Macro case. The step-up in energy demand growth reflects the lagged effects of energy price declines in the 1980s and low rates of price increase over the projection period, particularly for natural gas in the High Tech and Alternative Macro cases. Demand in the Alternative Macro case is also increased by more rapid output growth in the industrial sector generally, and particularly in some energy intensive-industries.

Nevertheless, industrial sector energy intensity declines in all three cases reflecting in general:

(1) a strong rate of penetration for technologies that use electricity;

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15 This decline reflects the increased availability of natural gas as a result of the completion of the TCPL pipeline in the late 1950s.

TABLE 4-8

Industrial Energy Demand by Fuel

(Average Annual Growth Rates – Percent)

	Other Oil	HFO	Natural Gas[1]	Electricity	Renewables[2]	Other[3]
1962-1991	2.6	-1.0	5.8	3.7	4.2	-0.9
1962-1971	10.1	5.8	12.0	5.3	7.9	-2.5
1971-1981	0.9	-1.3	3.5	3.4	2.9	1.4
1981-1991	-2.1	-6.4	2.9	2.6	2.2	-1.8

1 Includes natural gas used for bitumen production.
2 Includes solar, hog fuel and pulping liquor.
3 Includes steam, coke and coke oven gas, coal and LPGs.

TABLE 4-9

Industrial Energy Demand and Determinants

(Average Annual Growth Rates – Percent)

	Industrial RDP	Energy Prices	Manufacturing Capital Stock	Energy Demand
1962-1971	5.2	n/a	4.9	5.7
1971-1981	2.1	4.9	3.8	2.2
1981-1991	1.2	1.9	3.4	0.9
1991-2010:				
Current Tech	2.9	1.4	4.2	1.9
High Tech	2.9	0.8	4.2	2.3
Alternative Macro	3.4	0.8	4.3	3.1

(2) a continuing shift in the industrial RDP mix toward less energy intensive "other manufacturing" in both sets of macroeconomic assumptions; and

(3) specific energy efficiency developments.

Energy intensity in the Current Tech case declines by about 17 percent by 2010 (Figure 4-18). The projections reflect assumptions about specific energy efficiency developments including the increasing use of recycled materials in industries such as smelting and refining and iron and steel.

It also takes into consideration the impact of the continuing penetration of new process technologies in some industries, such as thermo-mechanical pulping (TMP) in the pulp and paper industry, and the growing automation and computerization of industrial processes. Under the High Tech and Alternative Macro assumptions, industrial energy intensity shows smaller declines over the projection period – 10 percent and 6 percent, respectively.

As illustrated in Figure 4-19, the share of electricity in total industrial sector energy demand rises in all three cases. The market share held by natural gas falls in the Current Tech case with rising relative natural gas prices, but remains relatively unchanged under the High Tech and Alternative Macro case assumptions. HFO is substituted for gas in the Current Tech case. The small decline in the share of renewables reflects a reduction in the use of wood waste and pulping liquor in the pulp and paper industry as the growing use of technologies which

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FIGURE 4-18
Industrial Energy Intensity

FIGURE 4-19
Industrial Energy Demand by Fuel
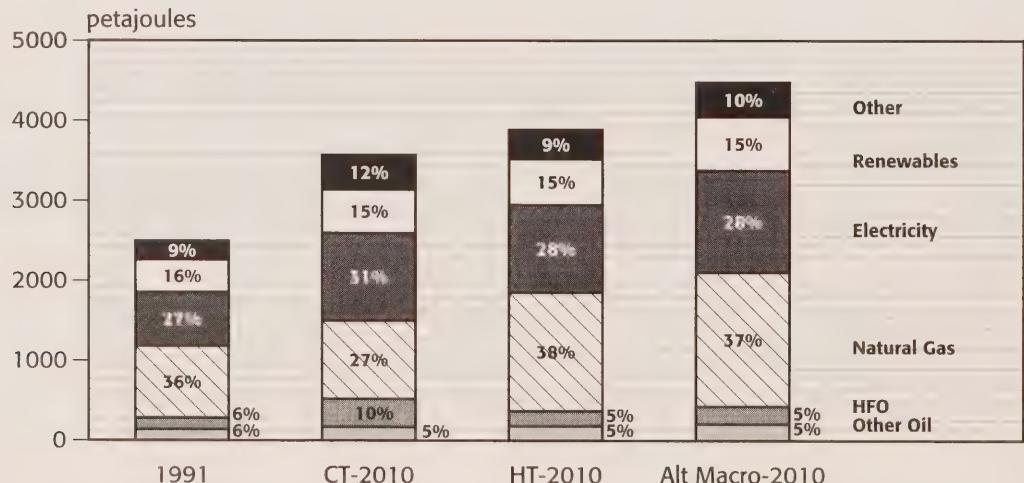
use wood more efficiently, reduce the supply of wood waste. The increase in the share of "other" fuels in the Current Tech case reflects the increased use of coal in Alberta bitumen production in the closing years of the projection.

4.5.3.5 Energy Demand by Industry

This section presents a general analysis of each industry within the industrial sector. Emphasis is placed on comparisons between the Current Tech and Alternative Macro cases. Tables 4-10, 4-11 and 4-12 provide detailed data on each industry's energy demand, RDP growth and fuel use.

Pulp and Paper

The Canadian pulp and paper industry competes on a global basis with producion facilities in the United States and northern Europe which are, in general, newer and more energy efficient. In Canada, the pulp and paper industry share of industrial RDP declined from 6.7

TABLE 4-10
Industrial Energy Demand by Industry

	Average Annual Growth Rates (Percent)				Share of Energy Demand (Percent)				
		1991 – 2010						2010	
	1978 - 1991	Current Tech	High Tech	Alt. Macro	1978	1991	Current Tech	High Tech	Alt. Macro
Pulp and Paper	1.5	1.0	1.3	2.6	28.4	30.8	26.0	25.4	27.8
Iron and Steel	-1.9	2.4	2.4	3.9	13.8	9.6	10.4	9.8	11.1
Smelting and Refining	1.1	3.2	3.3	4.0	7.3	7.6	9.7	9.0	8.9
Cement	-0.9	2.0	2.1	2.4	2.6	2.1	2.1	2.0	1.8
Petroleum Refining	6.0	1.1	1.1	1.3	2.0	3.7	3.2	3.0	2.6
Chemicals	2.0	2.7	2.7	3.2	8.2	9.5	10.9	10.2	9.6
Other Manufacturing	0.0	2.4	2.8	3.5	23.2	20.9	22.8	22.8	22.0
Mining	3.1	2.0	3.5	3.8	9.5	12.7	12.8	15.7	14.2
Forestry	-3.7	1.8	1.9	2.7	2.5	1.4	0.5	0.5	0.5
Construction	-2.7	2.0	2.1	2.2	2.7	1.7	1.7	1.6	1.4

TABLE 4-11
Industrial Real Domestic Product by Industry

	Average Annual Growth Rates (Percent)				Share of RDP (Percent)			
		1991 – 2010					2010	
	1978 - 1991	Current Tech	Alt. Macro	1978	1991	Current Tech	Alt. Macro
Pulp and Paper	-0.6	2.0	3.3	6.7	5.3	4.5	5.1
Iron and Steel	-1.3	2.5	4.0	3.4	2.5	2.3	2.7
Smelting and Refining	2.4	3.6	4.3	2.0	2.3	2.6	2.7
Cement	-1.8	2.9	3.2	2.2	1.5	1.5	1.4
Petroleum Refining	1.1	1.1	1.2	1.4	1.4	1.0	0.9
Chemicals	2.3	3.1	3.6	4.4	5.0	5.2	5.1
Other Manufacturing	1.3	3.6	4.3	42.8	43.5	49.8	50.9
Mining	0.3	1.6	1.9	15.8	14.2	11.2	10.6
Forestry	0.5	2.0	2.7	2.3	2.1	1.7	1.8
Construction	2.4	2.4	2.5	19.1	22.4	20.3	18.7

percent to 5.3 percent over the 1978 to 1991 period in part reflecting a weak global market for pulp in recent years. Nevertheless, the share of industrial energy demand accounted for by the pulp and paper industry rose slightly from 28.4 percent in 1978 to 30.8 percent in 1991 as energy intensity in this sector rose by more than 31 percent. The increase in energy intensity was largely attributable to increases in the shares of hog fuel and pulping liquor, fuels which have lower utilization efficiency factors. Energy demand growth over this time period averaged 1.5 percent per year.

Over the projection period we expect energy intensity in the Current Tech case to decline by about 16 percent because of increasing use of electricity[16] and HFO, as the availability of hog fuel and pulping liquor is reduced. Heavy fuel oil is projected to displace some natural gas in the Current Tech case. Growth in energy demand is projected to be more sluggish than in the past, averaging 1.0 percent per year from 1991 to 2010 in the Current Tech case. Under the Alternative Macro scenario, pulp and paper RDP growth rises with a resultant increase in energy demand growth to an average of 2.6 percent per year; energy intensity decreases a total of about 10 percent over the period.

The market share of electricity increases in all three cases. This is consistent with the shift to more electricity driven technologies such as thermo-mechanical pulping and chemical thermo-mechanical pulping (CTMP).[17] The pulp that is produced by these technologies typically has a lower water content than pulp produced using the more traditional Kraft process and also uses less energy in drying. These technologies also reduce the amount of waste wood and chemicals, thus reducing the availability and shares of hog fuel and pulping liquor. Another promising technology is the use of electric infrared profiling units, which are used for final drying of paper and newsprint.[18] These units have significant advantages over other processes, which use hot air for drying in that they reduce fire risk, improve paper quality and increase throughput.

The increasing use of recycled paper in paper production is also likely to reduce growth in energy demand. The energy required for the production of paper from recycled fibres has the lowest energy requirements per tonne of paper produced of all the current paper producing technologies.[19]

Iron and Steel

The industry's share of total industrial energy use declined from 13.8 percent in 1978 to 9.6 percent in 1991 while its share of industrial RDP declined from 3.4

percent to 2.5 percent. Over this same time period energy intensity declined 8 percent partly as a result of an increasing use of electrical processes which are inherently more efficient and also make use of scrap. Total energy demand in the sector declined from 310 petajoules in 1978 to 241 petajoules in 1991.

The Canadian iron and steel industry continues to be under pressure from the increasing globalization of the steel industry and world prices remain very close to production costs. With nearly half of all pig iron and steel produced in Canada now going to export, the industry needs to control costs and continue to improve both the cost and energy efficiency of the steel-making process.

Over the projection horizon, iron and steel industry energy demand and RDP grow 2.4 percent and 2.5 percent per year respectively. Energy intensity declines in total by about 4 percent in the Current Tech case between 1991 and 2010. Under the Alternative Macro assumptions, energy demand and RDP grow at 3.9 percent and 4.0 percent per year respectively, and energy intensity declines by only 2 percent over the projection period.

The general decline in energy intensity reflects the continuation of recent trends. These include a growing share of "mini-mills" which use electric arc furnaces and are charged exclusively with scrap steel. Mini-mills constituted 38 percent of all Canadian steel production

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16 Utilization efficiency factors for electricity and HFO are 100 percent and 87 percent respectively. Energy utilization efficiency factor refers to the proportion of a fuel's energy content that is actually harnessed as "usable" energy. For example, if fuel A has a utilization efficiency factor of 25 percent, this indicates that only 25 percent of fuel A's energy content is actually utilized in the process or activity. The remaining 75 percent of the energy content is lost as, for example, waste heat and exhaust. This 75 percent is called the efficiency loss of fuel A. Furthermore, if the utilization efficiency factor for fuel B is 50 percent, an amount of equivalent "usable" energy can be produced with half as much fuel B as fuel A. In the case of electricity, the utilization factor is 100 percent indicating that all of electricity's energy content is actually harnessed. While the utilization efficiency factor for natural gas is 85 percent, more natural gas (on an energy content per unit basis) is required to do the same work as electricity in the applications where both sources of energy can be used. Measured energy intensity (end use units of energy demand per dollar of output) is reduced when industries substitute more energy efficient fuels for less energy efficient fuels.

17 See *Potential Canadian Industrial Energy Efficiency Gains 1990-2010*, Energy Mines and Resources Canada, May 1992.

18 See *Opportunities for Electrotechnologies: Drying Applications in Industry*, Canadian Electrical Association, April 1993, 9114 U 859A.

19 *The Economically Attractive Potential for Energy Efficiency Gains in Canada, Case Study #6: Forest Industries*, prepared by Marbek Resource Consultants for Energy, Mines and Resources Canada, May 1991.

in 1992, up from 23 percent in 1980.[20] Another important trend is the general increasing use of scrap steel (recycling); about 50 percent of iron units for later processing into steel, now come from scrap. Natural Resources Canada estimates energy savings of up to 74 percent in the processing of scrap steel over raw iron ore. The increasing use of pulverized coal injection (PCI) direct reduced iron (DRI) and direct rolling, as well as greater precision and material savings associated with computer-assisted manufacturing technologies are expected to reduce energy requirements for steel production.

Mining[21]

Slightly more than 50 percent of the value of mined products in Canada are fuels (oil, natural gas and coal) while another 35 percent are metals (zinc, gold, copper, etc.). The extraction of these resources, especially fuels, can be extremely energy intensive. With the expansion of the oil and gas industry in western Canada,[22] the mining sector has accounted for an increasing share of total industrial energy use from 1978 to 1991, rising from 9.5 percent to 12.7 percent while its RDP share has shown some decline from 15.8 percent to 14.2 percent.

Increased bitumen production, an extremely energy intensive activity, accounts for a number of historical and future develpments in energy use in the mining sector. It accounted for about 30 percent of the 100 petajoule increase in total mining energy use from 1978 to 1991 and about one-third of the 43 percent increase in the mining sector energy intensity. Energy use in bitumen production also accounts for the large market share of natural gas in the mining sector (about 37 percent in 1991). Over the projection period, the market share of natural gas declines significantly to about 14 percent by 2010 in the Current Tech case as coal is substituted for higher priced gas in the closing years. In the High Tech and Alternative Macro cases, gas prices remain low, bitumen production increases and there is an increase in both energy demand and the natural gas share (Table 4-13). With higher bitumen production and energy demand in the High Tech and Alternative Macro cases, energy intensity rises by about 40 percent in each case compared to a 10 percent increase in the Current Tech case.

Mining sector energy intensity also rises, 0.3 percent and 1.8 percent per year in the Current Tech and Alternative Macro cases, respectively.

Smelting and Refining

The smelting and refining industry share of total industrial energy use over the 1978 to 1991 period held steady at about 7.5 percent while its share of industrial RDP increased from 2.0 percent to 2.3 percent. Energy demand grew 1.1 percent per year.

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20 *1992 Canadian Minerals Yearbook: Review and Outlook*, Energy Mines and Resources Canada.

21 The mining industry consists of metal mining, non-metal mining, oil and gas, and quarry and sand pit mining.

22 Alberta's share of total mining energy demand rose from 25 percent in 1978 to more than 50 percent by 1991.

TABLE 4-12
Fuel Market Shares by Industry – 1991
(Percent)

	Coal	Coke & Coke Oven Gas	DFO	Electricity	HFO	LFO & Kerosene	LPGs	Natural Gas	Hog Fuel & Pulping Liquor	Other[1]
Pulp and Paper	0.5	0.0	1.2	23.6	10.2	0.0	0.0	14.6	49.8	0.2
Iron and Steel	0.0	58.2	0.4	12.0	3.8	0.0	0.0	25.6	0.0	0.0
Smelting and Refining	4.8	1.1	0.3	75.7	4.8	0.0	0.0	13.4	0.0	0.0
Cement	36.9	4.3	0.7	11.6	3.3	0.0	0.0	28.7	0.0	14.5
Petroleum Refining	0.0	0.0	0.0	22.3	0.0	0.0	0.0	77.8	0.0	0.0
Chemicals	0.0	0.0	0.1	26.3	3.0	0.0	0.0	61.1	0.0	9.6
Other Manufacturing	1.7	0.6	2.2	22.8	2.5	0.4	3.1	66.3	0.0	0.5
Mining	0.2	1.3	13.2	33.0	5.5	1.1	1.2	37.5	0.0	7.0
Forestry	0.0	0.0	17.6	0.0	16.9	0.7	0.0	0.9	63.8	0.0
Construction	0.0	0.0	69.5	0.0	1.4	9.3	19.8	0.0	0.0	0.0

1 Includes steam, petroleum coke and solar.

Within this industry, about 85 percent of the energy is consumed in aluminum production. Electricity accounted for about 90 percent of the energy used in the aluminum industry in 1991 and for more than 75 percent of the fuels consumed in this sector, compared to 62 percent in 1978. The increasing use of electricity in this industry was primarily responsible for the 14.6 percent decline in energy intensity between 1978 and 1991.[23] However, given that most of the production technologies used in this sector are already electric driven, there is very little further opportunity for fuel substitution.

The Canadian aluminum industry continues to have access to generally inexpensive hydro-electric electricity compared to most other countries where aluminum is produced. Ten of the eleven major primary aluminum smelters in Canada are located in Québec, the remaining one is located in British Columbia. This price advantage allows aluminum produced in Canada to remain very competitive despite the transportation cost of importing bauxite from the Caribbean and South America.

Between 1991 and 2010, energy demand and RDP are projected to grow 3.2 percent and 3.6 percent per year, respectively, in the Current Tech case and 4 percent and 4.3 percent per year in the Alternative Macro case. Energy intensity declines 6 percent in the Current Tech case and 5 percent in the Alternative Macro case.

The projected declines in energy intensity are associated with the increasing use of more efficient electricity driven technologies and the growing use of recycled aluminum. The processing of scrap aluminum consumes only 5 percent of the energy required to process raw bauxite into aluminum. As a result, energy represents only 2 percent of a scrap aluminum smelter's cost compared to 26 percent for a primary aluminum smelter.

The potential for increased recycling appears to be great. Canada recycles 80 percent of aluminum beverage containers. More programs are being initiated by aluminum companies and governments to increase this rate and expand the sources of secondary aluminum. The automobile industry already accounts for about 80 percent of the demand for secondary aluminum[24] and their demand is expected to increase in order to meet the demand for lighter vehicles.

While the recycling of aluminum does have significant energy savings, we expect that recycled aluminum will constitute only a small portion of total Canadian aluminum production, and aluminum smelters in Canada will continue to produce most of their aluminum from raw sources.

Cement

Given the high weight and low value of product, cement plants are regionally diversified and generally are located close to the local/regional construction and materials manufacturing industries. Cement's shares in total industrial energy consumption and in industrial RDP have always been rather small at about 2 percent. From 1978 to 1991, energy demand and RDP declined 1.0 percent and 1.8 percent per year on average, respectively. Energy intensity declined 6.7 percent from

23 It should be noted that the increasing use of electricity does not necessarily imply a decrease in energy intensity for the economy as a whole at the primary level which includes fuels used in the generation of electric power. The means by which the electricity is generated is important. If hydro-electric power replaces fossil fuel generated power then there will be a decrease in primary energy intensity.

24 Secondary aluminum consists largely of recycled aluminum with some further processing that enhances its purity level and yields various types of alloys for specific purposes. Often, primary aluminum is injected into secondary aluminum processing to meet certain purity requirements for aluminum products.

TABLE 4-13

Energy Demand and Natural Gas Market Share for In-Situ Bitumen Production

	Current Tech case		High Tech and Alternative Macro cases	
	Energy Demand (Petajoules)	Natural Gas Market Share (Percent)	Energy Demand (Petajoules)	Natural Gas Market Share (Percent)
1991	63	37	63	37
2000	108	34	137	40
2010	97	14	201	44

1979 to 1991[25]; sharp drops in capacity utilization in 1990 and 1991 prevented this decline from being even greater.

The process of making cement has been moving steadily from a production known as the wet process (involving water) toward production based on the dry process which does not use water. The dry process is generally more energy efficient, using about 20 percent less energy than the wet process because there is no drying involved. The dry process also yields better quality cement. As of 1991, 80 percent of cement plants in Canada used the dry process compared to 65 percent of plants in 1978. It is this shift in production process which accounts for a large part of the decline in energy intensity.

Most of the energy consumed in a cement plant is used for the process of grinding and heating. Grinding is performed by electric driven rollers and accounts for about 19 percent of the plant's total energy consumption. Heating of the mixture can be performed by a variety of fuels. As much as 30 percent to 40 percent of production costs can be accounted for by fuel cost alone.[26] For this reason, the cement industry tends to be the most fuel price sensitive industry and can easily substitute fuels for heating. For more than a decade, the fuel mix for the cement industry has been moving away from natural gas and HFO to coal, petroleum coke and waste fuels.[27]

Energy demand and RDP are projected to grow at 2 percent and 3 percent per year respectively in both the Current Tech and Alternative Macro cases. Over the projection period we expect the technological trends that have emerged in the last few years to continue and result in a decline in energy intensity on the order of 10 percent in both scenarios. This decline comes as a result of:

(1) all plants switching to the dry process;

(2) increasing use of alternate materials for cement production such as fly ash and blast furnace slag (which do not require intense heating prior to processing);

(3) greater use of heat recovery to dry raw materials and perform pre-heating at the clinker burning stage;

(4) use of more efficient electric motors in the grinding process; and

(5) an increase in the current capacity utilization rate to full capacity.

Chemicals

The chemicals industry[28] in Canada is centred in Fort Saskatchewan (Alberta), Sarnia (Ontario), and Montreal (Québec) and produces four basic categories of chemicals: industrial grade organic chemicals, plastics and resins, industrial grade inorganic chemicals, and agricultural chemicals. These products are the most energy intensive to produce: their production accounts for almost 90 percent of the energy used in the chemicals industry.[29] The chemical industry's share of total industrial energy use has risen from 8.2 percent in 1978 to 9.5 percent in 1991 while its share in industrial RDP has increased from 4.4 percent to 5.0 percent. Energy intensity during this time declined a modest 0.3 percent per year while energy demand grew 2 percent per year, on average.

Most chemical processes require the infusion of heat energy, sometimes at very high temperatures. In some cases, electrical energy is required, either for cooling/heating or in electrolysis. Like the cement industry, the chemical industry is sensitive to fuel prices, since these can constitute a sizable portion of production costs. Consequently, facilities exist at many plants for ready fuel substitution when prices warrant. Since 1978 the industry has shifted away from heavy fuel oil to natural gas. Natural gas and heavy fuel oil had market shares of 45 percent and 22 percent, respectively in 1978, but by 1991, the shares had changed to 61 percent and 3 percent, respectively.[30]

Over the projection horizon we expect some small market share gains by heavy fuel oil reflecting relative

25   Data discontinuities make a 1978 to 1991 comparison inappropriate.

26   *Potential Canadian Industrial Energy Efficiency Gains: 1990-2010*, Energy Mines and Resources Canada, May 1992.

27   Waste fuels include paints and coatings, surplus used oils and greases, solvents, and tires.

28   It is important to note that the energy demand in this industry includes those fuels used to produce chemicals, but excludes fuel feedstocks that are direct ingredients in the chemicals themselves. For example, natural gas as an ingredient in the production of ammonia is not included, whereas natural gas burned for steam raising in the ammonia production is included.

29   *The Economically Attractive Potential for Energy Efficiency Gains in Canada, Case Study #5: Chemical Industries*, report prepared by Marbek Resource Consultants for Energy, Mines and Resources Canada, May 1991.

30   It should be noted that most of the gain in market share for gas and about half of the decline in HFO is due to the more predominant role that Alberta chemical industries, which are fed almost exclusively by natural gas, began to play throughout the 1980s. HFO use also dropped significantly in the Ontario and Québec chemical industries.

price changes but that gas will remain the predominant fuel. Energy demand and RDP in the Current Tech case grow, on average, by 2.7 percent and 3.1 percent respectively. Under the Alternative Macro assumptions, energy demand and RDP grow by 3.2 percent and 3.6 percent respectively. We project that energy intensities will decline a further 4 percent to 5 percent in the two cases owing to general improvements in the form of new heat recovery technologies, the use of more efficient boilers and furnaces and increased use of electricity.

Petroleum Refining

Energy intensity increased a substantial 83.6 percent between 1978 and 1991 reflecting: the use of more energy intensive refining processes required to reduce the output of HFO and to handle an increasingly heavy crude oil slate; the use of more energy intensive processes associated with the phasing out of leaded gasoline; development of new product mixes such as higher oxygenated gasoline and the need to meet tighter sulphur content requirements. As a result, energy demand grew 6 percent per year while RDP grew 1.1 percent per year, on average.

Over the projection horizon there is little difference between the Current Technology and Alternative Macro outcomes for this industry with energy and RDP rising on average at about 1.1 percent and 1.2 percent per year, respectively. In both cases, energy intensity in the petroleum refining industry increases by about 10 percent, as historical trend change in feedstock and product mix continue. Refinery margins are expected to remain tight reducing the incentive for firms to upgrade existing facilities.

Other Manufacturing

Other manufacturing, by its very nature, is the most diverse industry in terms of the types of goods which are produced and the types of fuels that are consumed. Production covers a broad spectrum from rubber and tobacco to heavy machinery and textiles. The share of this industry group in total industrial energy use has historically been the second largest after the pulp and paper industry and showed only a modest decline from 23.2 percent in 1978 to 20.9 percent in 1991. The sector's RDP share has held very stable over the same time period at about 43 percent. Energy intensity declined 16 percent over this same time period, the largest decline of any of our industry groupings within the manufacturing sector, while energy demand was essentially unchanged over this period.

A large proportion of the fuels consumed in this sector are used in space and process heating. Fuel market shares shifted substantially after the oil shocks: the share of HFO dropped from over 11 percent in 1978 to just over 2 percent in 1991, while the share of natural gas rose from 56 percent to more than 66 percent over the same time period. Electricity also made in-roads rising from an 18 percent to a 23 percent share.

For the projection period we expect energy intensity for this industry to decline a further 18 percent in the Current Tech case owing to further general improvements in the use of heat recovery technologies and a growing share of electricity as automation of production lines based on computer technology becomes more widespread. Projected energy demand and RDP average annual growth rates are 2.4 percent and 3.6 percent, respectively. In the Alternative Macro cases, energy demand is projected to grow 3.5 percent per year, RDP growth averages 4.3 percent and energy intensity declines a total of 12 percent.

Forestry

The forestry sector encompasses logging, sawmills and lumber operations. The main energy consuming operations of this industry involve the cutting of logs into "green lumber" and kiln-drying of cut lumber. Lumber drying operations have switched from fossil fuels to hog fuel as the principal heat fuel source.

The share for this industry declined in total industrial sector energy use from 2.5 percent to 1.4 percent while its share of total industrial sector RDP held steady at 2.1 percent over the 1978 to 1991 period. Energy intensity declined a total of 43 percent over this time period.

In the three cases, energy intensity is expected to improve a further 5 percent over the projection period.

Construction

The construction industry's total industrial energy share has been very small and declining from 2.7 percent to 1.7 percent over the 1978 to 1991 period. Construction, however, has historically held the second largest RDP share, rising from 19.1 percent to 22.4 percent over the same time period. Energy intensity declined a total of 49 percent between 1978 and 1991, the largest decline of any industry within the industrial sector.

A large proportion of industry energy requirements are met by DFO, whose market share dropped marginally from 72 percent in 1978 to 69 percent in 1991. Both light fuel oil and propane constitute the

remaining sources (about 10 percent and 19 percent in 1991, respectively) of fuel use. DFO is used in the running of heavy construction machinery while both LFO and propane are used for on-site space heating. The opportunities for fuel switching in this industry are limited.

Energy demand and RDP in the Current Tech case grow, on average, by 2.0 percent and 2.4 percent respectively. Under the Alternative Macro assumptions, energy demand and RDP grow by 2.2 percent and 2.5 percent respectively. Over the projection period our analysis suggests a modest 5 percent decline in energy intensity mainly reflecting improved efficiency for on-site heaters.

4.5.4   Transportation Sector

Energy consumption in the transportation sector constitutes 25 percent of total secondary energy demand. The sector is subdivided into road, air, marine and rail, with the road sector being the largest component (Figure 4-20). In 1991, road energy demand accounted for 80 percent of transportation energy demand; air accounted for 9 percent; and marine and rail accounted for 6 and 5 percent, respectively. The shares of road and air energy demand have increased over the last 20 years while those of the marine and railways have declined.

Motor gasoline and diesel fuel are the most important fuels in the transportation sector constituting 62 percent and 23 percent respectively of total transportation energy demand in 1991 (Figure 4-21). Of the total motor gasoline consumption, automobiles consume two-thirds and trucks the remaining one-third. Over two-thirds of DFO consumption is attributable to truck fuel use, nearly one-third to railway and marine use and a small proportion to car fuel use. Aviation turbine fuel (ATF), which is used exclusively in aeroplanes, and HFO, which is used exclusively in ships, account for 9 percent and 4 percent of the total, respectively. Alternative fuels – propane, natural gas and electricity – account for about 2 percent of total transportation energy use.

Historical Trends

Historically, transportation energy demand growth rates have varied considerably, due in part to its sensitivity to cyclical variations in economic activity. The pre-1973 era featured strong economic growth, low real energy prices and transportation energy demand growth averaging 5.7 percent per year. Following the oil price shock of 1973, rising energy prices led to slower economic growth, reduced transportation sector activity and improvements in fuel efficiency. Total transportation

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FIGURE 4-20
Transportation Modal Shares

1991
(1 825 petajoules)
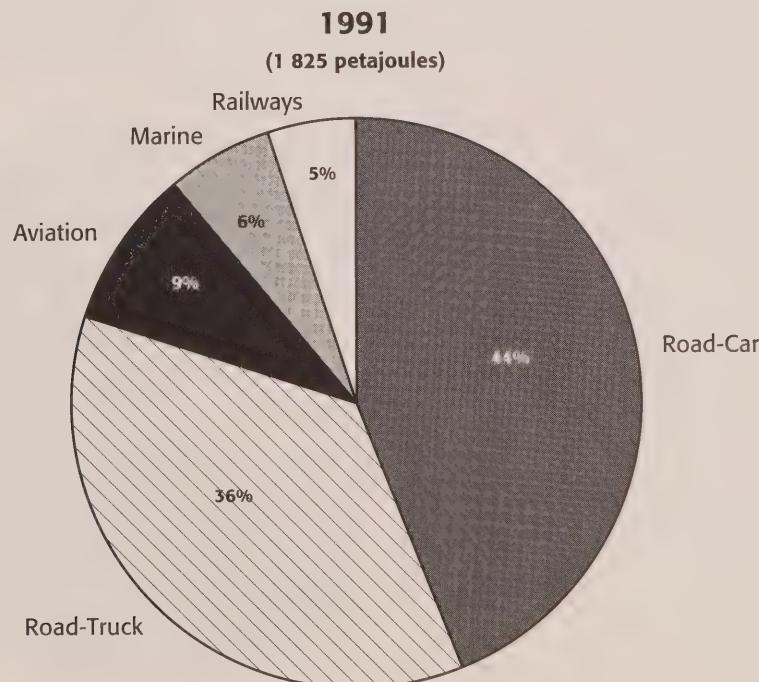
energy demand grew from 1 541 petajoules in 1973 to 1 825 petajoules in 1991, an average annual growth rate of about one percent.

Energy demand in each of the four main components of the transportation sector is driven by different factors. Consequently, we analyze each component separately. Further, although there are technical similarities between cars and commercial trucks, patterns of usage are sufficiently different to warrant separate analysis of the car and truck energy demand.

4.5.4.1 Car Energy Demand

Automobiles almost exclusively use gasoline. Changes in both car and truck energy demand reflect changes in the stock of vehicles, changes in the average stock fuel efficiency and changes in average annual vehicle kilometres driven. Car energy demand grew from 716 petajoules in 1973 to 804 in 1991, a growth rate of 0.6 percent per year. Over this period the car stock rose at 2.8 percent per year while average kilometres driven per car rose 0.4 percent per year. Fuel efficiency gains, averaging 2.6 percent per year significantly muted growth in automobile energy demand (Table 4-14).

Stock

The stock of cars is largely determined by demographic factors – population growth, household formation and labour force participation rates; and economic factors (i.e., real personal disposable income, operating costs and financing costs). Infrastructure developments and government policy initiatives such as road network plans and public transportation subsidies can also play a role.

From 1973 to 1991, growth in the car stock was steady, averaging 2.8 percent per year. This growth largely reflected increases in the number of households, increased female labour participation rates, and growth in real personal disposable income.

The number of cars per capita rose, on average, by 1.6 percent per year over the entire 1971 to 1991 period but increased more slowly, 1.1 percent per year, over the most recent six years. The number of cars per capita reached 0.46 in 1991. One would expect a slowing in the growth of the car stock as the number of cars per capita rises and the size of the car stock approaches the number of licensed drivers.

FIGURE 4-21
Transportation Fuel Shares

1991
(1 825 petajoules)

Other
HFO
ATF
2%
4%
9%
DFO
23%
Motor Gasoline
62%
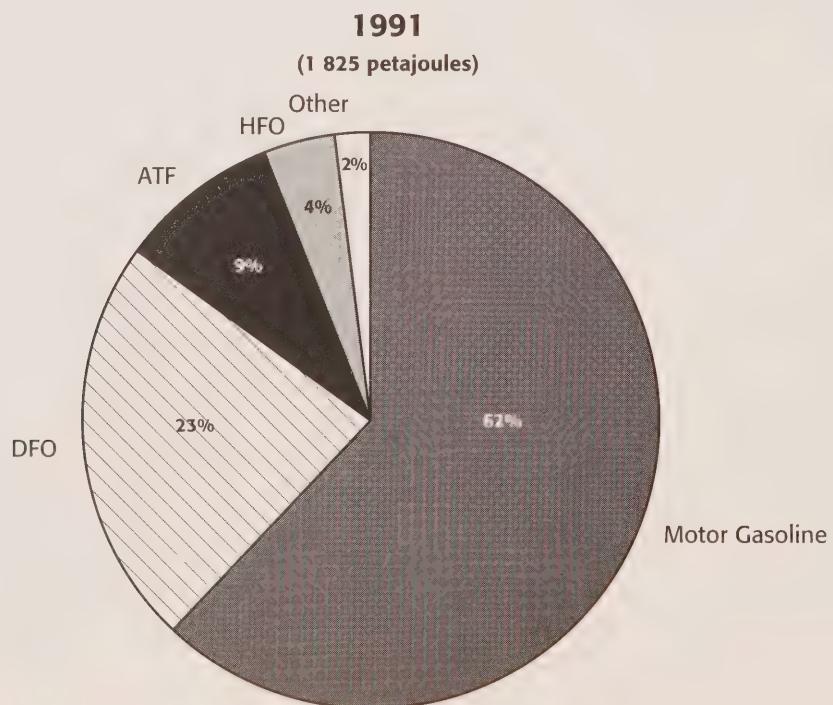
Average Stock Fuel Efficiency

Car operating costs rose dramatically in the ten year period following 1973 with the major influence being an average 4.5 percent per year increase in the real price of automobile motor gasoline. Increased operating costs encouraged consumers to purchase smaller cars: the share of compacts and sub-compacts in the total car stock rose from 46 percent in 1973 to 52 percent in 1983 and 60 percent in 1991.

Further, concerns regarding the security of energy supply led the U.S. government to impose Corporate Average Fuel Economy (CAFE) standards to regulate the fuel efficiency of new cars. This legislation led to design changes and improvements which increased car fuel efficiency. Car manufacturers began reducing the average weight of cars by replacing steel with high strength steel, aluminium and plastic, and more efficient

engine designs were introduced. These changes spilled over to Canada. Consequently, the fuel requirement of new cars, as measured by litres required per 100 km, dropped by 5.5 percent per year over the 1973 to 1983 period (Figure 4-22). Since 1983, average new car efficiency has stabilized at around the 10.0 L/100 km level as consumers' tastes have shifted back toward larger and more powerful vehicles in an era of declining real gasoline prices (real gasoline prices declined -1.8 percent per year, on average, between 1983 and 1991).

The new car efficiency improvements led to increases in average fuel efficiency of the car stock of 4.4 percent per year over the 1980 to 1987 period. The rate of improvement in the average stock fuel efficiency slowed to 2.4 percent per year between 1987 and 1991 reflecting the stabilization of average new car fuel efficiency.

TABLE 4-14
Car Energy Demand
(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Energy Demand	0.6	1.6	1.5
Stock	2.8	1.8	1.7
Stock Efficiency (L/100km)	-2.6	-0.3	-0.3
Average Kilometres Travelled	0.4	0.1	0.1
Real Personal Disposable Income	3.2	2.2	2.0
Real Auto Operating Cost	1.1	0.1	0.2
Households	2.4	1.6	1.6

FIGURE 4-22
Car Fuel Efficiencies
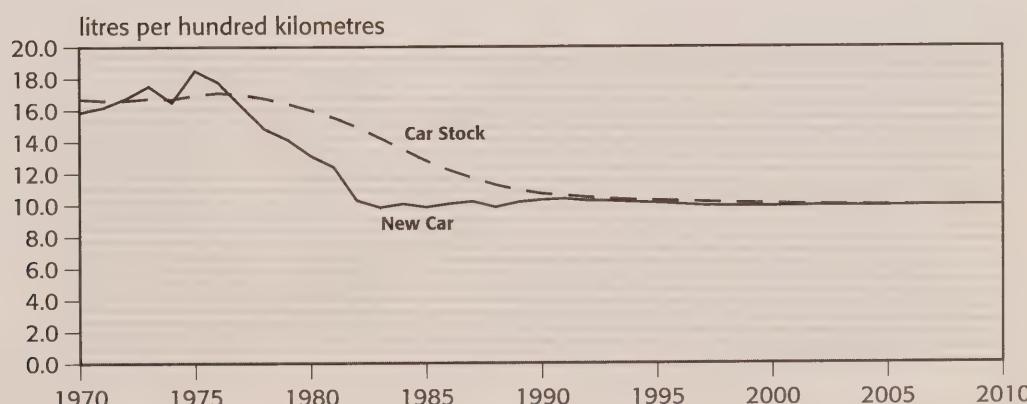
Average Kilometres Travelled

Annual average car kilometres travelled varies with economic circumstances, including cyclical movements in employment and income; with demographic factors such as the average age of the driving population. The intensity of vehicle use also reflects the number of automobiles per household and the age of the car stock. From 1973 to 1991, average annual kilometres driven per car increased at a modest average rate of 0.4 percent per year. However, the rate of increase fluctuated considerably within that period in response to changing energy prices and cycles in economic activity.

Projections

Car energy demand is projected to grow from 804 petajoules in 1991 to 1 088 petajoules in 2010, an average annual growth rate of 1.6 percent. This is a significant increase from the historical rate.

Fuel prices do not rise significantly over the projection period and we assume that no additional government initiatives, including more stringent CAFE standards, are implemented. We also assume that technological improvements which would on their own yield fuel economy gains are traded off against engines with greater horsepower, larger size and the increased penetration of features, such as air conditioning, as consumers continue to show a preference for bigger, higher performance and more comfortable cars. Consequently, and consistent with recent historical developments cited above, new car fleet efficiencies are assumed to remain stable at 10.0 L/100 kms with the effect that the average stock efficiency stabilizes at this level in 2002.

The effect of the stabilization in new car fuel efficiencies on total car energy demand is somewhat muted by lower than historical rates of growth in the car stock and average kilometres driven per car. The rate of increase in the car stock slows to 1.8 percent per year over the projection period. This reflects projected lower growth in real personal disposable income, lower rates of household formation and a slowing in the rate of increase in the female labour force participation rate.

In the Alternative Macro case, car energy demand is projected to grow to 1 063 petajoules by 2010, an average rate of growth of 1.5 percent per year, 0.1 percent slower per year than in the Current Tech and High Tech cases reflecting the fact that real personal disposable income rises somewhat more slowly in the Alternative Macro case.

4.5.4.2 Truck Energy Demand

In 1991, motor gasoline accounted for 53 percent of truck energy consumption while DFO accounted for 43 percent. The other 4 percent was composed of propane and natural gas. Truck energy demand grew from 465 petajoules in 1973 to 661 petajoules in 1991, a growth rate of 2.0 percent per year, while its share of road energy demand increased 2.7 percentage points to 45 percent. This growth reflected a 4.0 percent per year growth in the truck stock, offset by fuel efficiency gains that averaged 1.8 percent per year and by a 0.2 percent per year decrease in average truck kilometres driven. (Table 4-15).

Stock

Although truck energy demand and its determinants are discussed as a single element, energy demand for truck transport is analyzed separately for each of three distinct groups of trucks: light trucks (weighing up to 4 545 kg), medium/heavy trucks

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TABLE 4-15
Truck Energy Demand
(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Energy Demand	2.0	1.5	1.7
Stock	4.0	2.1	2.4
Stock Efficiency (L/100km)	-1.8	-1.0	-1.1
Average Kilometres Travelled	-0.1	0.4	0.4
Total RDP	2.8	2.5	2.6
Real Truck Diesel Price	1.0	1.0	1.1

(weighing 4 546 kg to 15 000 kg) and extra-heavy trucks (weighing over 15 000 kg).

Trucks are used in freight transport and as personal utility vehicles in place of automobiles. Consequently, changes in the truck stock reflect changes in the level of economic activity and the industrial structure, as well as operating costs and finance charges. Competitiveness relative to alternative modes of freight transport is also a factor.

From 1973 to 1991, truck stock growth averaged 4.0 percent per year, but displayed strong cyclical variations. A delayed response to the recession of the early 1980s saw the truck stock fall 8.9 percent between 1983 and 1984. Similarly, after following the growth in the economy during the rest of the 1980s, truck stock fell by 5.0 percent between 1990 and 1991. Over the entire 1973 to 1991 period there appears to have been a slowing in the growth of the truck stock.

The composition of the truck stock has also changed. The share of light trucks, which often function as passenger automobiles, increased as a proportion of the total truck stock from 76 percent in 1973 to 90 percent in 1991 but accounted for 47 percent of truck energy demand. Use of extra-heavy trucks increased at the expense of medium/heavy trucks to maximize payload fuel efficiency although they use more fuel per kilometre compared to medium size trucks. The share of extra-heavy trucks in the stock of medium and extra-heavy trucks increased from 16 percent in 1973 to 48 percent in 1991 while their share of energy consumption increased from 27 percent in 1973 to 72 percent in 1991.

Average Stock Fuel Efficiency

Average truck stock efficiency is influenced by operating costs, of which the price of fuel is a major component. Efficiency gains are particularly important because the trucking industry is forced to control costs in an increasingly competitive freight hauling business environment.

Improvement in the average stock fuel efficiency has been due to the increases in the stock share of light trucks as well as technical improvements and on increased use of DFO in medium/heavy trucks. Diesel trucks offer better fuel efficiency and longer engine life than motor gasoline fuelled trucks. The proportion of diesel fuelled medium/heavy trucks rose from 2 percent in 1973 to 39 percent in 1991. The average truck stock efficiency improved 1.8 percent per year over the 1973 to 1991 period in spite of the offsetting influence of a greater use of extra-heavy trucks.

Average fuel efficiency increased more slowly at an average annual rate of 0.3 percent during the 1990 to 1992 recession reflecting lower load rates and a general aging of the stock. After the recession we assume that the rate of improvement in the average truck stock fuel efficiency will return to the long term trend.

Average Kilometres Travelled

The intensity of truck usage (average truck kilometres travelled) varies with economic conditions and the changing composition of the truck stock. The share of extra-heavy trucks in the total truck stock has tended to increase average annual kilometres travelled while the increasing proportion of light trucks has tended to decrease average annual kilometres travelled.

Average annual truck kilometres driven declined at 0.2 percent per year over the 1973 to 1991 period. However, the rate of change varied widely within this period reflecting cyclical variation in economic activity. For example, average annual truck kilometres driven dropped by 12.6 percent between 1990 and 1991.

Projections

Truck energy demand is projected to rise from 661 petajoules in 1991 to 874 petajoules in 2010, an average annual growth rate of 1.5 percent in both Current Tech and High Tech cases. This represents a slowing in growth of 0.5 percent per year from the rate experienced over the previous eighteen years.

Trends in the size of the truck stock and truck stock fuel efficiency both contribute to the slowdown in growth in truck energy demand. The truck stock increases more slowly reflecting slowing growth in the demand for truck transportation services and a tendency to use more load efficient extra-heavy trucks.

The rate of improvement in truck stock efficiency is assumed to slow to 1.0 percent per year between 1991 and 2010. This slowdown is the result of stable projected motor gasoline and DFO prices (the real price of truck diesel grows at 1.0 percent per year) as well as the continuing increase in the share of extra-heavy trucks.

Average kilometres driven per truck increases 0.4 percent per year between 1991 and 2010 compared to small rate of decrease historically as the share of extra-heavy trucks, which tend to be intensively utilized, increases.

In the Alternative Macro case, truck energy consumption is projected to reach 912 petajoules by 2010, an average rate of growth of 1.7 percent per year, 0.2 percent per year higher than the growth rate projected in the Current and High Tech cases. The higher growth

rate reflects greater demand for transportation services in a more goods-intensive economy.

4.5.4.3 Aviation Energy Demand

Air transportation energy consumption is almost entirely in the form of aviation turbine fuel. Air energy consumption increased from 126 petajoules in 1973 to 166 petajoules in 1991, an average growth rate of 1.5 percent per year although the rate of growth fluctuated considerably (Table 4-16). Air energy demand reflects changes in total air passsenger kilometres flown and aircraft fuel efficiency. These are largely determined by real personal income growth and the price of aviation fuel (a major component of the cost of flying). These, in turn, determine total air passenger kilometres flown and aircraft efficiency.

Passenger kilometres flown rose by 4.6 percent per year from 1973 to 1991 despite the fact that the cost of flying increased 10.5 percent per year, on average. On the other hand, energy consumption per passenger kilometre flown fell at a rate of 3.1 percent per year over the period reflecting improvements in technical fuel efficiency and in plane deployment strategies.

Projections

Energy demand is projected to increase from 166 petajoules to 274 petajoules by 2010, an average rate of growth of 2.7 percent per year. The increase in growth from the historical period reflects a slowing in the rate of increase in the cost of flying and recovery from the drop of 9.7 percent during the 1990-92 recession. The energy demand projection is the same in all three cases.

4.5.4.4 Railway Energy Demand

Railways are mainly used for bulk transport. In 1991, iron ore and concentrates, bituminous coal and wheat accounted for nearly 40 percent of total railway freight traffic with most of these volumes destined for marine export. Railway energy consumption is made up entirely of diesel fuel oil.

The demand for rail transportaton services and therefore rail energy demand responds to variations in industrial activity, particularly in the mining, agriculture, forestry and manufacturing industries and rail freight rates. The latter are in part a function of the price of DFO.

The energy demand decreased from 101 petajoules in 1973 to 83 petajoules in 1991, an average rate of decline of 1.1 percent per year (Table 4-17). Over this period, Rail-RDP[31] rose 0.4 percent per year and the real price of DFO rose 4.2 percent per year. Energy intensity in the rail transport sector, as measured by railway energy demand per dollar of Rail-RDP, declined at an average rate of 1.5 percent per year.

Projections

Energy demand for rail transport is projected to increase much more rapidly than historically, 1.4 percent per year, on average, over the projection period. The level of demand rises from 83 petajoules in 1991 to 109 petajoules by 2010. Rail-RDP grows at 2.9 percent per year, much faster than the 0.4 percent average annual growth which occurred over the 1973 to 1991 period and the annual average increase in the real price of rail diesel of 0.2 percent is much lower than the historical rate of 4.2 percent per year. Energy intensity in the rail sector is assumed to continue to decline at the historical rate of 1.5 percent per year. In the Alternative Macro case, railway energy demand reaches 113 petajoules by 2010, only slightly higher than projected demand in the Current Tech and High Tech cases.

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31 For analytical purposes, we define a measure of the demand for rail transport services, "Rail RDP", as an index on output in the four industries just listed above.

TABLE 4-16

Aviation Energy Demand

(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Energy Demand	1.5	2.7	2.7
Passenger Kilometres	4.6	5.3	5.4
Real Personal Disposable Income	3.2	2.2	2.0
Cost of Flying	10.5	0.3	0.1
Aviation Intensity (PJ / Pass. km)	-3.1	-2.6	-2.7

4.5.4.5 Marine Energy Demand

As with the rail sector, marine transport is mainly used to move bulk goods, destined for export. Marine tonnage, itself a function of industrial activity[32], is the major determinant of marine energy demand. The real price of marine fuel is also an important.

In 1991, 60 percent of marine energy consumption was in the form of HFO and 40 percent DFO. Marine energy demand decreased from 132 petajoules in 1973 to 112 petajoules in 1991, a rate of decline of about one percent per year but, as in other sectors, with cyclical great variation. Marine tonnage increased at a rate of 1.0 percent per year from 1973 to 1991 as Marine-RDP rose by 1.3 percent per year. The average real price of marine fuel, a weighted average of the prices of HFO and DFO, rose sharply, by 12.0 percent per year, between 1973 and 1983, but subsequently fell at a 6.3 percent annual rate to 1991. Marine energy intensity, as measured by marine energy demand per dollar of Marine-RDP declined at an average rate of 2.2 percent per year (Table 4-18).

Projections

Marine energy demand increases 1.5 percent per year on average, from 112 petajoules in 1991 to 149 petajoules by 2010 in the Current Tech and High Tech cases reversing the historical trend of decline. Marine-RDP is projected to grow at 3.1 percent per year, more than double the historical rate of growth while the average real price of marine fuel rises slowly at 0.7 percent per year. Fuel efficiencies are assumed to continue to increase but at a lower than historical rate.

In the Alternative Macro case, marine energy demand reaches 170 petajoules by 2010, growing at a rate of 2.2 percent per year. Marine-RDP rises more rapidly at 3.8 percent per year than in the other two cases, reflecting the more goods intensive economic structure in the Alternative Macro set of macroeconomic assumptions.

4.5.4.6 Total Transportation Sector Energy Demand Projection

Total transportation sector energy demand is projected to increase from 1 825 petajoules in 1991 to 2 494 petajoules in 2010 or by 1.7 percent per year in each of the Current and High Tech cases (Table 4-19). In the Alternative Macro case, projected total

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32 For our analysis we measure this industrial activity as Marine-RDP, an index of real output in mining, agriculture and forestry.

TABLE 4-17

Railway Energy Demand

(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Energy Demand	-1.1	1.4	1.6
Railway RDP	0.4	2.9	3.5
Real Railway Diesel Price	4.2	0.2	0.4
Railway Intensity (PJ / $Rail RDP)	-1.5	-1.5	-1.9

TABLE 4-18

Marine Energy Demand

(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Energy Demand	-0.9	1.5	2.2
Marine RDP	1.3	3.1	3.8
Marine Tonnage	1.0	1.8	2.2
Average Real Fuel Price	3.5	0.7	0.9
Marine Intensity (PJ / $Marine RDP)	-2.2	-1.6	-1.6

transportation energy demand reaches the slightly higher level of 2 533 petajoules by 2010.

As in the past, projected transportation sector energy use primarily consists of refined petroleum products over the projection period (Figure 4-23). Specifically, motor gasoline dominates but, because of increasing consumption of aviation and other fuels, the market share held by motor gasoline falls slowly from 62 percent in 1991 to 60 percent in 2010 in the Current Tech and High Tech cases and 59 percent in 2010 in the Alternative Macro case. The share of aviation turbine fuel is expected to increase to 11 percent in 2010 in all three cases, up from 9 percent in 1991. We project little change in the diesel fuel oil share over the projection period in all three cases from its 1991 value of 23 percent. The share of HFO continues to decline in the Current Tech and High Tech cases, falling to 3 percent of total transportation energy demand in 2010 from 4 percent in 1991; it remains at 4 percent in the Alternative Macro case because of more robust marine energy demand growth.

Alternative fuels such as natural gas, propane and electricity continue to gain in importance but only slightly relative to other fuels. Their combined share in road energy demand is projected to increase from 2.4 percent in 1991 to 3.3 percent in 2010. We have allowed for modest growth in the use of natural gas and propane

in vehicles over the projection period, from 32 petajoules in 1991 to about 57 petajoules in 2010. These fuels tend to be most economical and convenient when used in commercial vehicle fleets. Their use in private vehicles is limited at present by the lack of an extensive fuel distribution network and consumer acceptance.

4.5.5 Non-Energy Hydrocarbon Use

In addition to being used as energy sources, hydrocarbons are also consumed as non-energy products such as petrochemicals, asphalt, and lubricating materials. Non-energy hydrocarbon use in Canada amounted to 649 petajoules in 1991, or about 9 percent of total end use demand for hydrocarbons. Of this, 435 petajoules was used for petrochemical feedstocks, 122 petajoules for asphalt, and 92 petajoules for the production of lubricants, greases and other non-energy petroleum products.

Non-energy use of hydrocarbons, particulary as petrochemical feedstocks, is highly sensitive to relative prices for natural gas. Over the projection period, non-energy consumption of hydrocarbons rises to 1034 petajoules in the Current Tech case, an average annual increase of 2.5 percent. With the lower gas prices of the High Tech case, consumption rises 2.7 percent per year to 1 072 petajoules (Table 4-20).

TABLE 4-19

Transportation Energy Demand by Mode

(Average Annual Growth Rates – Percent)

	1973-1991	Current & High Tech 1991-2010	Alternative Macro 1991-2010
Road	1.2	1.5	1.6
Motor Gasoline	0.2	1.4	1.5
DFO	7.8	1.7	1.8
Other	1.1	1.5	1.5
Aviation	1.5	2.7	2.7
ATF	1.7	2.7	2.8
Other	-3.5	1.3	1.3
Marine	-0.9	1.5	2.2
HFO	-1.4	1.3	2.0
DFO	0.4	1.8	2.5
Railway			
DFO	-1.1	1.4	1.6
Total	0.9	1.7	1.7

4.5.5.1 Petrochemical Feedstock Production Outlook

Demand for petrochemical feedstocks is determined primarily by relative feedstock prices and demand for primary petrochemicals.[33] Primary petrochemicals are those which are produced in the first step of the petrochemical production process in which natural gas, oil and natural gas liquids (NGL) are converted into petrochemicals. The principal primary petrochemical groups are:

- Olefins (ethylene and co-products propylene, butylenes) which are produced through steam cracking of NGLs or oil fractions, are used in the production of plastics, chemicals and fibres.

- Aromatics (benzene, toluene, xylenes) produced as co-products with olefins and directly from oil fractions. These are also used in the production of plastics, chemicals and fibres.

- Methanol is produced from natural gas. Among other uses, including the production of resins, paints and solvents, methanol is used in the production of methyl tertiary butyl ether (MTBE)

33 Much of the discussion on petrochemical feedstock production and domestic consumption is based on a report prepared by W.D. Onn Consulting Service, October 1993, for the National Energy Board entitled An Estimate of Feedstock Consumption for Primary Petrochemical Production in Canada, 1990-2010.

FIGURE 4-23
Transportation Energy Demand by Fuel
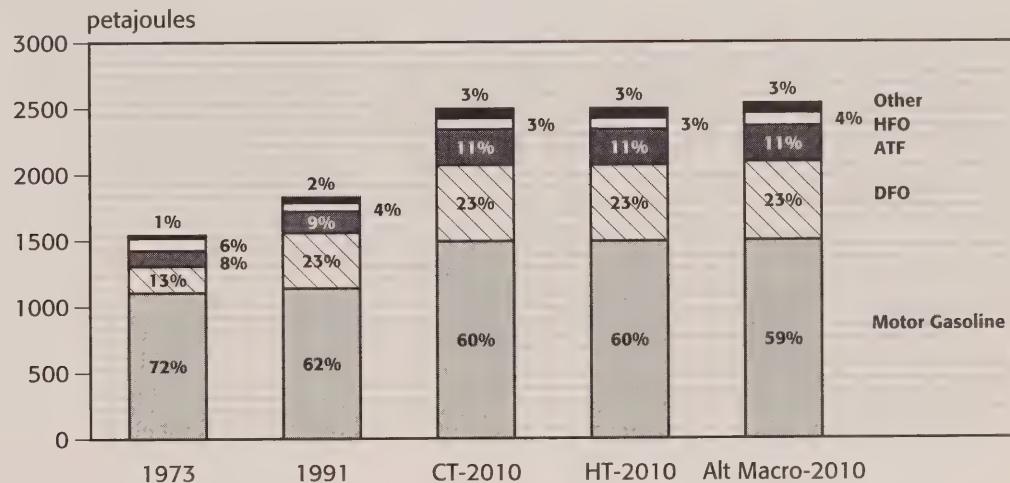
TABLE 4-20
Non-Energy Uses
(Petajoules)

	1973	1991	Current Tech 2000	Current Tech 2010	High Tech 2000	High Tech 2010
Petrochemical Feedstocks	122	435	610	775	635	813
Asphalt	138	122	133	140	133	140
Lubes and greases	38	34	37	41	37	41
Naptha	23	10	11	12	11	12
Petroleum Coke	23	31	37	45	37	45
Other Non-Energy Uses	17	17	19	21	19	21
Total Non-Energy	362	649	847	1 034	871	1 072

which provides the oxygenate requirement for reformulated gasoline.

- Ammonia, which is produced from natural gas, is largely used as a fertilizer.

North American petrochemical demand growth is expected to be moderate; however, there appears to be opportunities for growth in exports to Asia. Canadian producers continue to be very competitive with U.S. producers given exchange rate expectations and, for those using gas or natural gas liquids, a continued large difference between Canadian and U.S. gas prices.[34] Freer trade with the U.S. should continue to be beneficial for the petrochemical industry.

Ethane based plants are very cost competitive on a world basis. The projected U.S./Canadian gas price differential supports production of lower cost ethylene derivatives and offsets transportation cost disadvantages, allowing continued exports to the U.S. and Asia. As a result, Alberta production is projected to increase by 4 percent per year through 2000, and 3 percent per year thereafter.

The Sarnia plants are more dependent on the more slowly growing North American petrochemicals market. Further, the Sarnia facilities, while competitive, do not have the substantial feedstock cost advantage that Alberta plants enjoy. Production by these plants is projected to grow 2.5 percent per year through 2000, dropping to 2 percent annually from 2000 to 2010.

The aromatics business has been generally flat over the past several years, reflecting recession in most industrial countries, excess capacity, and a tendency toward saturation in the markets for key derivatives such as styrene and phenol/acetone in the industrial countries. From 1983 to 1992, growth in U.S. benzene consumption averaged about 2 percent per year. During this period, growth in Canadian production averaged roughly one percent per year.

Major chemical consulting firms generally project a market recovery in line with our assumptions about future economic growth. Aromatics production in central Canada is projected to grow with the U.S. economy, at roughly 2 percent per year, since Canadian and U.S. markets are closely related and Canada exports significant volumes. Alberta production grows more rapidly at 2.5 percent per year, as it serves the rapidly growing Far East market, and is considered efficient and cost competitive.

The spread between Canadian and U.S. gas prices provides a $15 to $22 per tonne feedstock cost advantage to the Canadian methanol industry. This was roughly 10 to 15 percent of the value of the product in 1993. In addition, the Free Trade Agreement eliminated a substantial U.S. import duty on methanol, further improving the Canadian competitive position.

The U.S. Clean Air Act is also providing a market boost for methanol because of the requirements for additional quantities of MTBE. In the Current Tech case, Canadian methanol production is projected to grow at 5 percent per year through 1996, then average about 2.5 percent per year to 2010 reflecting the pattern of demand for MTBE.

This methanol production forecast does not include any increased direct consumption of methanol as transportation fuel. Methanol is one of the "alternate fuels" approved to meet more stringent emission regulations mandated for California and some other areas starting towards the end of the decade. If methanol should in fact become one of the "alternate fuels", demand for Canadian production could expand very substantially, to levels well beyond those projected here.

The ammonia market has been in a slump worldwide over the past few years, with production stagnant or declining in most countries, although conditions have improved recently. A number of industry analysts believe nitrogen demand will stage a moderate comeback in the mid-1990's and Canadian production is likely to continue to be competitive in North America, in part based on gas price differentials. For the rest of the current decade, Canadian ammonia production is projected to grow at an annual rate just over 2 percent, dropping to 1.5 percent after 2000.

Petrochemical Feedstock Domestic Consumption: Current Tech Case and High Tech Case

The production of some petrochemicals, the most important being ethylene and co-products, features flexibility between the various hydrocarbon feedstock categories. Due to price and security of supply advantages, the feedstock mix for these products in Canada, as well as the world generally, is projected to move towards a lighter slate with increased use of NGL and less reliance on oil based feedstocks.

From 1981 to 1991, demand for NGL as petrochemical feedstock increased at an average annual rate of 11.6 percent (Table 4-21). NGL consumption continues to grow rapidly in the Current Tech case, increasing 4.4 percent per year from 154 petajoules in 1991 to 348 petajoules in 2010.

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34 For further discussion, see Chapter 6, Section 6.6.2.1.

Use of natural gas as feedstock in petrochemical production has increased at an average annual rate of 5 percent over the past ten years. In the Current Tech case, natural gas consumption grows at approximately 2.5 percent per year from 156 petajoules in 1991 to 248 petajoules in 2010.

Consumption of oil based feedstocks has been declining at an average annual rate of one percent per year over the 1980s. The continued shift toward NGL in olefin production, and slow growth in the production of aromatics are assumed to limit growth in demand for oil based feedstocks. As a result, consumption of oil based feedstocks grows more slowly than that of NGL and gas, in the Current Tech case, expanding at an average rate of 1.9 percent per year from 125 petajoules in 1991 to 180 petajoules in 2010.

The lower North American gas prices in the High Tech case produce a further shift away from oil feedstocks toward NGL, particularly ethane, in olefin plants. However, this shift is limited in Ontario and Quebec facilities due to plant flexibility. The major impact of lower North American gas prices is to make Alberta ethylene and B.C. methanol and ammonia more competitive around the world.

4.5.5.2 Asphalt, Lubes and Greases, and Naphtha

Asphalt production is the most important non-energy hydrocarbon use outside the petrochemical industry.

Road paving activity is the primary determinant of asphalt demand as paving accounts for 75 percent of asphalt use. The trend toward asphalt recycling[35] will also influence hydrocarbon use in asphalt production. Asphalt recycling requires a significantly reduced quantity of hydrocarbons per unit of asphalt production. Over the past ten years, RDP in road and highway

construction as a group has increased by one percent per year, while the quantity of non-energy hydrocarbons used for asphalt production has actually declined by 0.5 percent per year.

The greatest influence on paving activity in the short run will be the infrastructure initiative put forth by the federal government. After dividing the additional infrastructure investment between highways and building projects, Informetrica Ltd. estimates that road, highway and airstrip construction will increase by roughly 23 percent in 1994, and a further 6 percent in 1995.[36] After 1995, highway construction is assumed to decline back to normal levels and then grow slowly over the rest of the projection period. Our assumptions reflect the Informetrica estimates.

Taken together, the infrastructure program, and a continued increase in the rate of asphalt recycling, imply increases in asphalt-related hydrocarbon demand of approximately 22 percent in 1994 and 5 percent in 1995. Demand is then assumed to return to normal levels in 1996 and to grow at roughly 0.5 percent per year thereafter.

Demand for lubricating oils and greases, petroleum coke, and non-petroleum products as a group grows at an average annual rate of 1.4 percent over the projection period.

4.6 END USE ENERGY DEMAND BY REGION

The distribution of energy demand by region in Canada generally reflects regional differences in population, levels of economic activity, industrial

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35 Asphalt recycling involves combining recycled asphalt with virgin asphalt.

36 Informetrica, Winter 1993 Reference Outlook, February 1994.

TABLE 4-21
Petrochemical Feedstock Consumption
(Petajoules)

	1973	1981	1991	Current Tech 2000	Current Tech 2010	High Tech 2000	High Tech 2010
Natural Gas	41	96	156	199	248	214	271
Oil	82	139	125	149	180	149	180
NGL	0	51	154	262	348	272	362
Total Petrochemical Feedstocks	123	286	435	610	775	635	813

structure and fuel availability. Ontario was by far the largest regional consumer of energy in 1991 reflecting the fact that its population and RDP are the largest of any Canadian region. Québec is the next largest in all three respects; energy demand in Québec is boosted by the relatively large share of heavy industries in its economic structure. Alberta is a relatively large consumer of energy reflecting the great importance of the oil and gas supply industry in its economy (Figure 4-24).

4.6.1 Atlantic

End use energy demand in the Atlantic region increased 0.2 percent per year, on average, in the 1970s. It declined by about the same rate in the 1980s in response to the lagged effects of energy price increases, lower growth in households and the reduction in energy use per unit of output. In the 1970s and 1980s, energy intensity declined, on average, 1.1 percent and 2.4 percent per year, respectively.

Fuel choices are mainly oil and electricity. Wood waste and coal are used in the industrial sector and wood is also an important option in the rural part of the residential sector. Natural gas is not available at present in the Atlantic region and this results in relatively higher use of oil for non-transportation purposes. Our analysis

suggests that gas could be available from offshore Nova Scotia[37] by the end of the projection period under the Current Tech set of assumptions.

The effect of off-oil programs, energy conservation and general concern for security of supply resulted in a drop in the share of oil used for non-transportation purposes from 49 percent of total Atlantic end use energy demand in 1971 to 28 percent in 1991. Electricity and renewables were the principal replacements for oil products (Figure 4-25). The share of oil used in the transportation sector in total energy demand in the region increased from 30 percent in 1971 to 34 percent in 1991.

Population and household growth in the Atlantic region have been slow historically and continue to be the slowest in the nation, at 0.3 and 0.7 percent per year, respectively, over the projection period. Projected industrial and commercial RDP growth is modest as well, at 1.5 percent per year, on average. Consequently, energy demand is projected to grow at only 1.0 percent annually between 1991 and 2010 in the Current and High Tech cases. In the Alternative Macro case, higher assumed industrial RDP growth results in energy demand growth of 1.2 percent per year and a slower

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37 For further details, see Chapter 6.

FIGURE 4-24

Distribution of End Use Energy Demand by Region

1991
(7 301 petajoules)
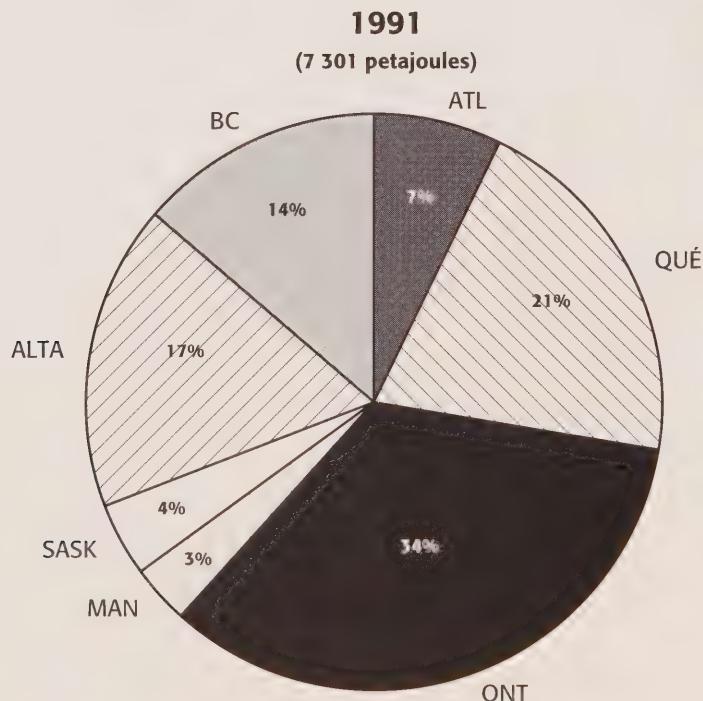
decline in energy intensity. Energy intensity declines by 0.7 percent annually in the Current and High Tech cases, but only 0.4 percent per year on average in the Alternative Macro case.

The share of oil in total regional energy demand is projected to continue to decline in each of the three cases. All of the decline occurs in non-transportation oil demand; the share of transportation sector oil consumption increases somewhat over the projection period (Figure 4-25).

Electricity's share is projected to increase more slowly than in the past, from 22 percent of end use energy demand in 1991 to 25 percent in 2010 in all three cases. The share of renewables is projected to decline in the three cases, reflecting resource constraints on the use of wood and wood wastes.

4.6.2 Québec

End use energy demand in Québec increased at an annual average rate of 1.5 percent in the 1970s but declined 0.3 percent per year, on average, in the 1980s. The reduction in energy demand was largely due to slow growth in the number of households, the lagged impact of energy price increases from the 1970s and a concentration of growth in economic activity in service industries. Energy use per unit of RDP declined 1.7 percent per year between 1976 and 1981 and 2.4 percent per year in the 1980s.

Historically, Québec has consumed the largest amount of electricity. As a highly industrialized province with abundant and relatively cheap electricity,

Québec has attracted a number of electricity-intensive industries: e.g., aluminum and pulp and paper. The flexibility of fuel choice in the province's industrial sector exceeds all other regions with many plants being able to switch to HFO, natural gas or electricity in response to price variations. Further, about 22 percent of households in the residential sector have a dual heating capability.

Electricity's share of end use energy demand increased from 18 percent in 1971 to 36 percent in 1991 in response to relatively low prices and incentives provided by Hydro Québec to encourage switching to electricity (Figure 4-26). The share of natural gas in end use energy demand increased from 4 percent in 1971 to 14 percent in 1991, while the share accounted for by wood and wood wastes also increased from 4 to 7 percent over the same period. The share of oil used for non-transportation purposes declined from 46 percent in 1971 to 15 percent in 1991, while the share of oil used for transportation remained more or less unchanged in the last 20 years.

Projected growth for industrial and commercial RDP is 2.9 percent and 1.8 percent per year respectively, in the Current Tech and High Tech cases. In the Alternative Macro case, industrial RDP is projected to grow 3.5 percent per year while Commercial RDP is projected to increase 1.7 percent per year. In all three cases, Québec's population and number of households are expected to grow 0.8 percent and 1.2 percent, respectively; slower than the national average of 1.1 percent and 1.6 percent.

FIGURE 4-25
End Use Energy Demand by Fuel – Atlantic
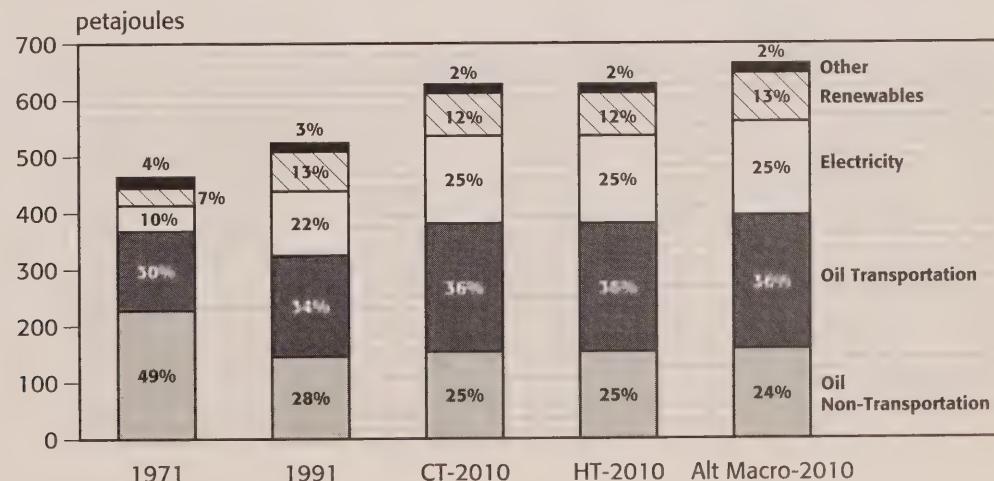
Total end use energy demand is projected to grow at 1.4 percent per year, on average, in the Current and High Tech cases and 1.8 percent per year in the Alternative Macro sensitivity. The rate of decline in energy intensity is slower than in the past, 0.9 percent per year in the Current Tech case, 0.8 percent in the High Tech case and 0.6 percent in the Alternative Macro sensitivity.

The trend towards a greater proportion of electricity is projected to continue. By 2010, electricity's share of total end use energy demand reaches 40 to 41 percent in all three cases. Natural gas, on the other hand, maintains market share in the High Tech and Alternative Macro cases but loses market share in the Current Tech case because of the more rapid rate of increase in natural gas prices. The other fuels generally maintain their market shares in all three cases.

4.6.3   Ontario

Ontario's end use demand for energy increased at an average rate of 1.4 percent per year in the 1970s slowing to 0.4 percent per year in the 1980s. The slowdown was largely due to slower growth in household formation and improvements in energy efficiency. Energy intensity declined at an annual rate of 2.2 percent in the 1980s compared to a 1.4 percent decline in the 1970s.

The consumption of oil products in non-transportation uses was largely displaced by electricity and natural gas. Electricity's share increased from 12 percent in 1971 to 19 percent in 1991, and the natural gas share increased from 25 to 31 percent (Figure 4-27). The share of non-transportation oil declined from 27 percent to 12 percent over the 1971 to 1991 period. The share of transportation sector oil consumption increased slightly while the share of renewables increased from 2 to 4 percent.

Ontario's industrial RDP is projected to grow at approximately 3.5 percent in both the Current and High Tech cases, significantly higher than the 2.6 percent average annual growth rate of commercial RDP. In the Alternative Macro sensitivity, industrial RDP increases at 4.2 percent per year. Projected population and household growth of 2.9 percent and 1.9 percent per year are well above the national averages.

In each of the three cases, Ontario's end use energy demand is projected to increase more rapidly than the demand of any province except Alberta, with annual average growth of 1.8 percent in the Current Tech case, 2.0 percent in the High Tech case and 2.3 percent in the Alternative Macro case. Growth in industrial RDP of 3.5 percent in the Current Tech and High Tech cases and 4.2 percent in the Alternative Macro case is the main force driving energy demand in each case. Energy intensity is projected to decline annually by 1.1 percent in the Current Tech case, 0.9 percent in the High Tech case and 0.8 percent in the Alternative Macro sensitivity.

The market share of electricity is projected to grow modestly. The relatively slow growth rate in part reflects the impact of Ontario Hydro's demand side management programs.

FIGURE 4-26

End Use Energy Demand by Fuel – Québec
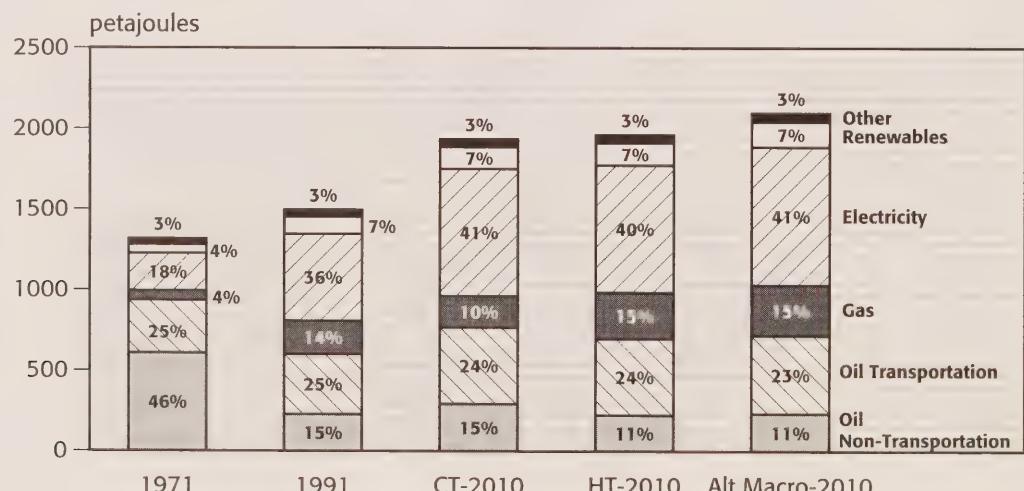
The share of oil for non-transportation energy uses is projected to increase from 12 percent to 13 percent in the Current Tech case, mainly due to the increase in the of natural gas relative to that of HFO. In the High Tech and Alternative Macro cases, the share of non-transportation oil decreases reflecting a more modest increase in the price of gas relative to oil products.

The share of transportation sector oil consumption increases from 24 percent in 1991 to 25 percent by 2010 in the Current Tech case. In the High Tech case, transportation oil's share remains unchanged while it decreases to 23 percent in the Alternative Macro case because of the additional demand for transportation services by a more goods-intensive economic structure. The share of renewables, at 4 percent in 1991, remains unchanged in the three cases.

4.6.4   Manitoba

End use energy demand in Manitoba in the 1970s and 1980s increased at an annual average rate of about 0.1 percent, the lowest in Canada, as a result of the relatively lower growth in Manitoba's economy and 1.7 percent per year decline in energy intensity.

In response to the price increases associated with the oil shocks, fuel usage in Manitoba over the 1970s and 1980s shifted to natural gas and electricity from non-transportation demand for oil (Figure 4-28). The transportation oil share changed little, while the non-transportation oil share declined from 18 percent in 1971 to 10 percent in 1991.

Energy demand growth is projected to average 0.8 percent per year in the Current Tech case, 0.9 percent in the High Tech case and 1.0 percent in the Alternative Macro case over the projection period. The projected energy demand growth rates are among the lowest in Canada, reflecting modest rates of RDP growth in the industrial and commercial sectors and relatively low rates of household formation and population growth. Industrial RDP is projected to grow 2.6 percent in both the Current Tech and High Tech cases. Commercial RDP is assumed to grow 2.0 percent per year in the two cases. In the Alternative Macro case, industrial and commercial RDP are projected to increase 3.0 percent and 1.7 percent per year, respectively. Population and the number of households increase 0.7 percent and 1.2 percent per annum, respectively.

The projected use of energy per unit of output is expected to decrease at annual average rates of 1.3 percent in the Current Tech case, 1.2 percent in the High Tech case and 1.0 percent in the Alternative Macro case.

Natural gas remains competitive with heavy fuel oil in the Current Tech case, despite the projected increase in natural gas prices. Natural gas's share of total energy demand in 2010 is unchanged from its level in 1991 at 31 percent. The market share of non-transportation oil is projected to decline reflecting competition from both gas and electricity in the Current Tech case. Electricity's share rises to 26 percent in 2010 from 23 percent in 1991, in part due to greater penetration of technologies that use electricity.

FIGURE 4-27
End Use Energy Demand by Fuel – Ontario
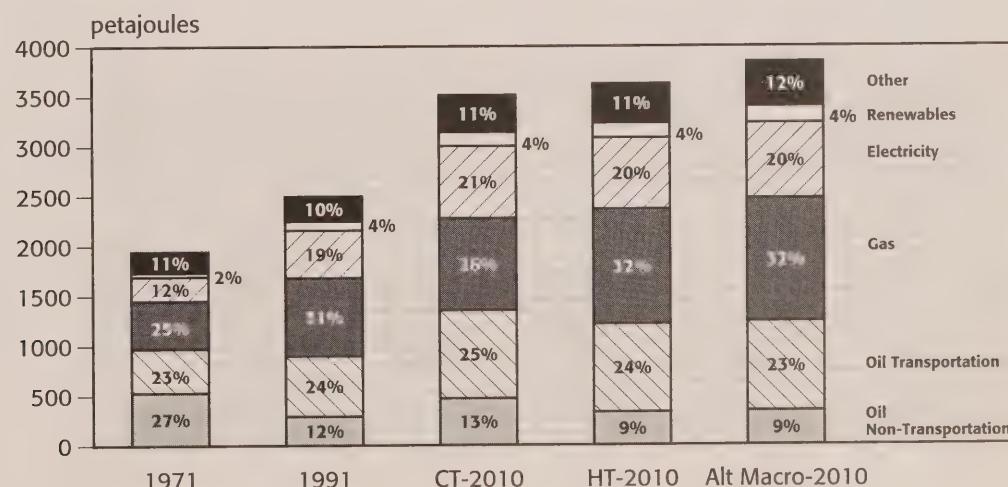
In both the High Tech and Alternative Macro cases, the natural gas share increases to 33 percent by 2010 further displacing the use of oil. Electricity's share, at 26 percent in 2010, is the same as in the Current Tech case. In all three cases, the share of renewables is the same in 2010 at about 4 percent.

4.6.5 Saskatchewan

End use energy demand in Saskatchewan in the 1970s and 1980s grew at annual average rates of 1.2 and 0.9 percent respectively. Energy use per unit of output was essentially unchanged between 1976 and 1981 but decreased by 1.5 percent per year between 1981 and 1991. Saskatchewan's population increased by 0.5 percent per year between 1976 and 1991. Over the same period, provincial RDP growth was 2.1 percent per year, on average.

Electricity's share of total energy demand increased from 8 percent in 1971 to 15 percent in 1991 (Figure 4-29), due to growing use of electricity-based technologies and some substitution of electricity for natural gas in new chemical plants and petroleum refining facilities. Over the same period, the natural gas share decreased slightly. The share of oil products used in the non-transportation sector declined from 19 percent in 1971 to 15 percent in 1991 while improvements in vehicle efficiency standards reduced the share of transportation oil use from 28 percent to 26 percent over this same time period.

Over the projection period, industrial RDP and commercial RDP are projected to grow at average annual rates of 1.1 percent and 1.5 percent respectively in each of the three cases. Population growth is 0.4 percent per year, while the number of households grows at twice that rate in each case.

Relatively slow economic and population growth generate slow growth in provincial energy demand of 0.8 percent annually in the Current Tech case, 1.0 percent in the High Tech case and 1.2 percent in the Alternative Macro case over the projection period (Figure 4-29). The structure and relatively slow growth of the Saskatchewan economy tend to limit opportunities for improvements in energy efficiency. In addition, the mining sector, which plays a large role in the Saskatchewan economy, is expected to display modest increases in energy use per unit of output. Consequently, small annual average declines in energy intensity are projected – 0.7 percent in the Current Tech case, 0.4 percent in the High Tech case and 0.3 percent in the Alternative Macro case. These are the second smallest rates of reduction in energy intensity in the country.

Electricity's share of end use energy demand increases from 15 percent in 1991 to 16 percent by 2010 in all three cases. There is no change in the share of natural gas in the Current Tech case but the gas share rises from 38 percent in 1991 to 41 percent in 2010 in both the High Tech and Alternative Macro cases reflecting the lower absolute and relative price of gas. In the Current Tech case, non-transportation oil's share remains more or less unchanged; in each of the other two cases, the share of non-transportation oil declines as natural gas displaces oil products. Transportation oil's share decreases in all three cases. The share of renewables remains at about 3 percent.

FIGURE 4-28

End Use Energy Demand by Fuel – Manitoba
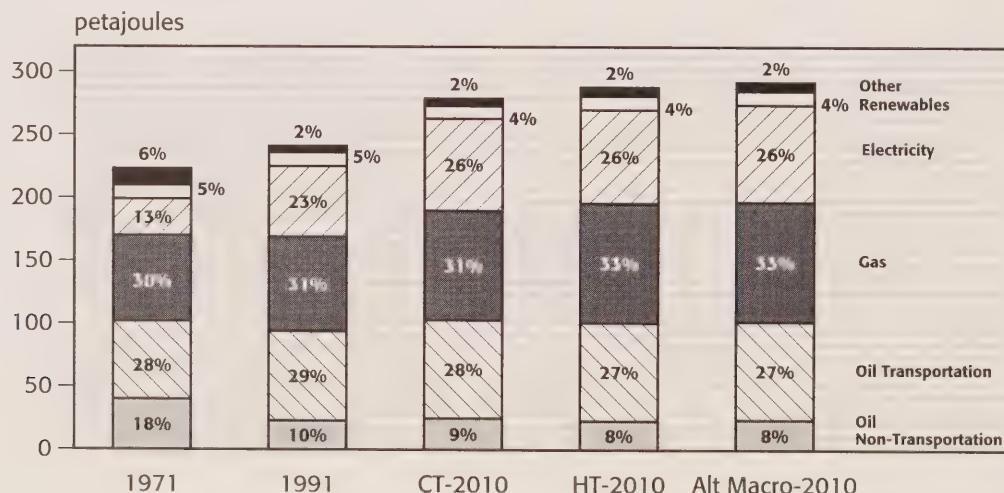
4.6.6 Alberta

The dominant role of the province's oil and gas sector and its associated energy requirements combined with strong demographic growth resulted in average annual increases in Alberta's end use energy demand of 7.8 percent in the 1970s and 2.5 percent in the 1980s, the highest rates of growth for any region during these periods. Alberta has been the only region in Canada to show consistently rising energy use per unit of output at 2.3 percent per year between 1976 and 1991. The mining sector experienced a steady increase in energy intensity at an average annual rate of 2.3 percent reflecting increases in the very energy intensive production of bitumen largely from mining plants and in situ operations.

Because natural gas is relatively cheap and readily available, Alberta has the highest gas and the lowest non-transportation oil shares in the country (Figure 4-30). The share of oil used for transportation in total energy demand declined from 27 percent in 1971 to 18 percent in 1991. Alberta has the lowest electricity share among the provinces; however, its share increased from 7 percent of end use demand in 1971 to 12 percent in 1991.

FIGURE 4-29

End Use Energy Demand by Fuel – Saskatchewan
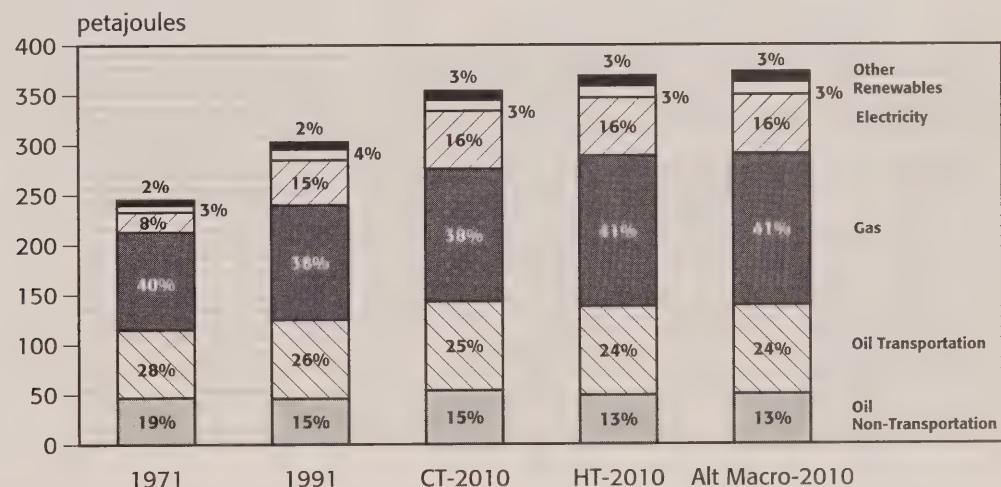
FIGURE 4-30

End Use Energy Demand by Fuel – Alberta
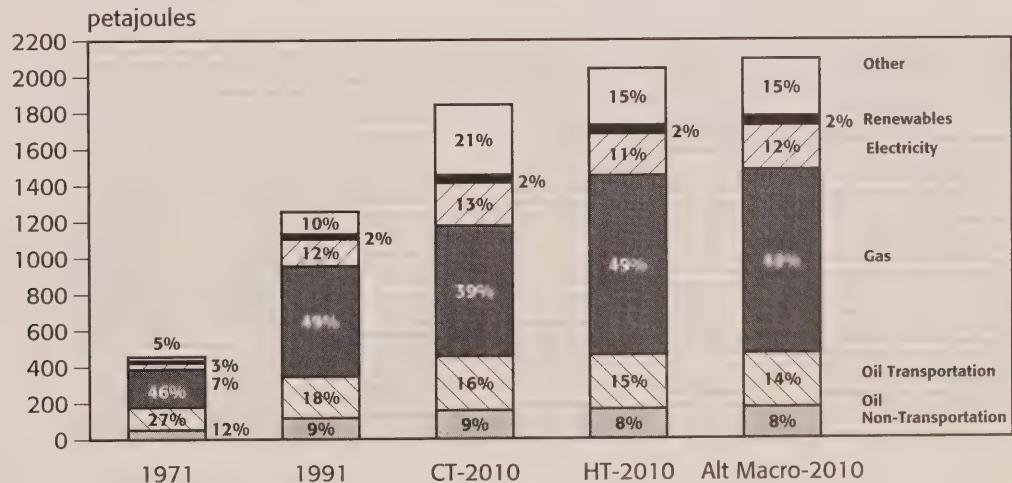
Alberta's commercial and industrial RDP are expected to grow 2.2 percent per year in the Current Tech and High Tech cases, over the projection period; in the Alternative Macro case, projected industrial and commercial RDP grow 2.5 percent and 2.0 percent, respectively. Population growth is expected to be 1.3 percent per year in each of the three cases. Over the projection horizon, end use energy demand grows, on an annual average basis, 2.1 percent in the Current Tech case, 2.6 percent in the High Tech case and 2.7 percent in the Alternative Macro case (Figure 4-30). Provincial energy intensity declines at an average annual rate of 0.2 percent in the Current Tech case, the smallest rate of decline among all the regions, and actually increases in both the High Tech and Alternative Macro cases. These movements reflect the net effects of declining energy intensity in the residential and commercial sectors, largely or more than offset by increasing intensity in the industrial, mining and petrochemicals sectors.

In the Current Tech case, electricity's share remains constant through 2010; the share decreases slightly in the High Tech and Alternative Macro cases. The share of natural gas decreases to 39 percent by 2010 in the Current Tech case, reflecting mainly increased use of NGL in the petrochemical sector and a substitution of coal for gas in bitumen production in the closing years of the projection period. The increasing use of coal in bitumen production accounts for a large portion of the doubling in the aggregate share of other fuels to 22 percent in 2010. In the High Tech and Alternative Macro cases, the natural gas share rises to 49 percent by 2010. In these cases, gas use for bitumen production doubles

reflecting both its lower price relative to coal and the expansionary effects of lower fuel costs on bitumen production and improved technology.

The potential to switch from oil products to other fuels is comparatively limited in Alberta because there is little consumption of LFO and HFO; thus the share of non-transportation oil, consumption changes little over the projection period in each case. The transportation oil share decreases in all three cases and the share of renewables remains unchanged at 2 percent.

4.6.7 British Columbia, and the Yukon and Northwest Territories

Average annual growth of end use energy demand in British Columbia and the Yukon and Northwest Territories[38] (B.C.) averaged 3.0 percent in the 1970s and 1.2 percent in the 1980s, rates exceeded only by Alberta, reflecting the strength of the B.C. economy and relatively high rates of provincial household formation. The provincial economy grew 3.6 percent per year between 1976 and 1981 and 2.2 percent in the following ten years while the number of households increased at 3.9 percent during the 1976 to 1981 period and at 2.2 percent in the 1980s. Energy intensity decreased by 2.0 percent per annum in the 1976 to 1981 period and 1.0 percent in the 1980s.

Between 1971 and 1991, the share of natural gas rose from 15 percent to 24 percent of the end use energy demand while that of electricity increased from 15

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38 British Columbia accounted for about 97 percent of the total B.C. and Territories energy demand in 1991.

FIGURE 4-31

End Use Energy Demand by Fuel – B.C. & Territories
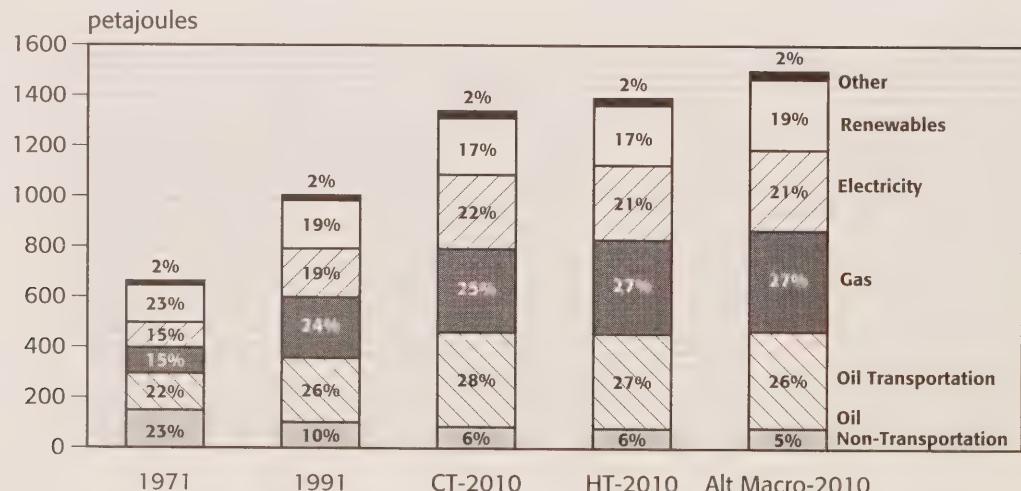
percent to 19 percent. Both natural gas and electricity displaced oil in non-transportation uses. The share of transportation oil use increased from 22 percent to 26 percent between 1971 and 1991 (Figure 4-31). The share of renewables decreased over the period from 23 percent to 19 percent, reflecting a decline in the use of wood and wood wastes in the pulp and paper industry; nevertheless, B.C. remains the largest consumer of renewables.

Industrial RDP is projected to increase, on average, 2.4 percent per year in both the Current Tech and High Tech cases while commercial RDP is projected to increase 2.9 percent in the two cases. In the Alternative Macro case, industrial and commercial RDP grow at 2.9 percent and 2.7 percent, respectively. Number of households grows at 2.3 percent per year, in all three cases.

End use energy demand in B.C. is projected to grow by 1.5 percent per year in the Current Tech case, 1.7 percent in the High Tech case and 2.1 percent in the Alternative Macro case reflecting these relatively strong rates of economic growth and household formation. Growth in energy demand ranks third behind Alberta and Ontario. Energy intensity declines 1.3 percent per year in the Current Tech case, 1.1 percent in the High Tech case and 0.7 percent in the Alternative Macro case, on average, over the projection period.

The natural gas share of total end use energy demand in B.C. rises from 24 percent in 1991 to 25 percent in 2010 in the Current Tech case and to 27 percent in both the High Tech and Alternative Macro cases. Electricity's share also rises, partly because its use as a process fuel in the pulp and paper industry increases

as it replaces the use of hog fuel and pulping liquor. The share of non-transportation oil declines from 10 percent in 1991 to about 6 percent in 2010 in all three cases. The share of oil used in the transportation sector is expected to remain more or less unchanged from its 1991 level over the projection period. The share of renewables drops slightly to 17 percent in the Current Tech and High Tech cases in 2010 from 19 percent in 1991. In the Alternative Macro case, the share of renewables is expected to remain unchanged reflecting assumed stronger growth in the pulp and paper industry and an associated increase in the availability of wood waste and pulping liquor.

4.7   PRIMARY ENERGY DEMAND BY FUEL

Primary energy demand is composed of end use demand, as discussed in the previous sections of this chapter, plus the energy consumed in the energy supply industry, including conversions and losses associated with the production of electricity.

4.7.1   Primary Demand for Oil

End use energy requirements, which include energy demand in the residential, commercial, industrial and transportation sectors, as well as oil used for non-energy purposes, are, in aggregate, the largest component of primary oil demand. Oil products used by the energy supply industry (own-use) and the requirements for electricity and steam production (conversions) make up the remaining share of primary oil demand.

The distribution of primary oil demand by product type changed dramatically between 1971 and 1991

TABLE 4-22
Primary Demand for Oil by Product
(Percent Shares)

| | | | 2010 | | |
	1971	**1991**	**Current Tech**	**High Tech**	**Alternative Macro**
Aviation Fuels	3	5	7	7	7
Motor Gasoline	29	34	34	36	36
Light Fuel Oil & Kerosene	23	8	4	3	3
Diesel Fuel Oil	10	20	20	21	21
Heavy Fuel Oil	24	12	16	13	13
Asphalt	3	4	3	3	3
Other	8	16	16	17	17
Total	100	100	100	100	100

(Table 4-22). Fuels for which natural gas and electricity could be easily substituted, such as light fuel oil, kerosene and heavy fuel oil, lost significant market share. Demand for these products fell in the residential, commercial and industrial sectors between 1971 and 1991 (Table 4-23). The heavy fuel oil share was cut in half while the combined share of light fuel oil and kerosene dropped by three-quarters. Demand for oil for use in transportation, where substitution is difficult and expensive, grew slowly.

Over the projection period the demand for primary oil products increases 1.6 percent per year on average in the Current Tech case, 1.3 percent per year in the High Tech case and 1.4 percent per year in the Alternative Macro case (Table 4-23). Most fuels maintain shares close to their 1991 levels except for heavy fuel oil, light fuel oil and kerosene (Table 4-22). The heavy fuel oil share increases to 16 percent of primary oil demand by 2010 in the Current Tech case as rising natural gas prices give HFO a relative price advantage. Almost all of the gain occurs in the industrial sector. In the High Tech and Alternative Macro cases, the HFO share is little changed by 2010.

The combined share of light fuel oil and kerosene continues to drop. Much of this fuel is consumed in the residential and commercial sectors and projected energy demand growth by households and commercial sector enterprises is modest over the projection period as natural gas is expected to be the fuel of choice for newly constructed residential and commercial buildings.

The motor gasoline share in primary oil demand is projected to hold steady or increase in all three cases, reflecting our assumptions that there will be no change in corporate fuel efficiency standards over the projection period and that the stock of cars and trucks will continue to grow modestly.

4.7.2 Primary Demand for Natural Gas

The primary demand for natural gas includes all end use demand (including natural gas feedstocks), natural gas used to generate electricity and steam, natural gas used as fuel in pipeline transmission (as well as losses) and natural gas used as fuel in reprocessing plants.

From 1971 to 1991, the primary demand for natural gas almost doubled from 1 222 petajoules to slightly

TABLE 4-23

Primary Demand for Oil by Use

(Petajoules)

			2010		
	1971	**1991**	**Current Tech**	**High Tech**	**Alternative Macro**
Sectoral Demand					
Residential	621	246	191	144	141
Commercial	300	86	88	67	63
Industrial	477	284	522	371	429
Transportation	1 314	1 791	2 428	2 428	2 467
Petrochemical	76	125	180	180	180
Other Non-Energy	180	214	259	259	259
Total End Use	2 968	2 745	3 667	3 448	3 539
Own Use and Conversions					
Energy Supply Industry	214	231	315	297	304
Electricity Generation[1]	113	130	172	175	187
Steam Production	n.a.	3	3	3	3
Butanes used for Blending	-5	-79	-90	-90	-90
Refinery LPG	22	53	71	71	71
Total Own Use and Conversions	344	338	472	457	465
Total Primary Demand	3 313	3 083	4 138	3 905	4 015

1. Including electricity exports

more than 2 300 petajoules (Table 4-24). Most of this increase reflected increased end use demand. Natural gas used to generate electricity and steam reached a peak of more than 200 petajoules in 1973 but declined steadily thereafter to 1991[39]. The use of gas for pipeline transmission doubled, paralleling a doubling of end use natural gas demand.

Over the projection period, primary demand for natural gas is projected to grow, on average, at 1.3 percent per year, in the Current Tech case and 2.6 percent and 3.1 percent per year in the High Tech and Alternative Macro cases respectively (Table 4-24). The doubling in growth from the Current Tech case to the High Tech case reflects the much lower relative price of natural gas in the latter case.

Canadian natural gas is used for electricity generation by both domestic and U.S. electric utilities and by self-generators in the industrial sector. Over the projection period natural gas use for electricity generation triples from 1991 levels in the Current Tech case with the greatest gains in Ontario and British Colulmbia. Each of these regions accounts for about one-third of the demand for gas for electricity generation in 2010. In the High Tech and Alternative Macro cases, natural gas demand for electricity generation in 2010 is more than twice the projected demand of the Current Tech case.

Natural gas is consumed in the transportation of natural gas as pipeline fuel and losses. The amount of natural gas required as fuel for transportation is dependent on the amount of natural gas transported. In 1991, the transportation requirement for exported gas amounted to 57 petajoules and is projected to reach 83 petajoules by 2010 in the Current Tech case and 104

petajoules in the High Tech and Alternative Macro cases. Natural gas required for the transmission and distribution of natural gas to domestic markets is projected to rise from 140 petajoules in 1991 to 191 petajoules by 2010 in the Current Tech case and 247 petajoules in both the High Tech and Alternative Macro cases.

4.7.3 Primary Demand for Natural Gas Liquids

Natural gas liquids are comprised of ethane, propane, butanes and pentanes plus. Primary demand for NGL, excluding pentanes plus, grew at 9.2 percent per year on average between 1971 and 1991. End use demand for propane and butanes in the residential, commercial and industrial sectors grew more slowly while demand for butanes used for gasoline blending grew more quickly than primary energy demand for NGL during that period. The switch from leaded to unleaded gasoline and improvements in the process for extracting butanes from natural gas resulted in average increases of 25 percent per year during the 1970s in the use of butanes in gasoline blending. The introduction of vehicles fuelled by propane resulted in a 27 petajoule increase by 1991 in propane demand in the transportation sector from a 1981 level of only 2 petajoules. Consumption of ethane grew 13 percent per year, on average, between 1981 and 1991 as a result of increased natural gas production (a supply-side effect) and greater demand for ethane as a petrochemical feedstock for ethylene production (Table 4-25).

In contrast to the rapid growth of the 1980s, propane demand in the transportation sector is assumed

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39 Virtually all of the decline in the use of natural gas for electricity generation was outside of Alberta.

TABLE 4-24
Primary Demand for Natural Gas
(Petajoules)

	1971	1991	2010 Current Tech	2010 High Tech	2010 Alternative Macro
End-Use Demand	1 018	2 015	2 390	3 046	3 208
Electricity Generation [1]	100	79	246	538	570
Pipeline Fuel and Loss	97	197	274	350	350
Reprocessing Fuel	8	11	17	22	22
Primary Demand [2]	1 222	2 302	2 927	3 956	4 150

1 Includes natural gas used to produce steam and electricity exports.
2 Excludes reprocessing shrinkage.

to increase only 1.6 percent per year between 1991 and 2010 in all three cases. Aggregate residential, commercial and industrial demand for butane changes very little over the projection period in all three cases while non-energy butane demand increases 9.3 percent per year in the Current Tech case and 9.6 percent in the High Tech and Alternative Macro cases. However, total end use demand for butanes increase at 3.0, 3.2 and 3.3 percent per year in the Current Tech, High Tech and Alternative Macro cases respectively. Ethane demand is projected to grow at 3.9 percent per year in the Current Tech case and 4.1 percent in the High Tech and Alternative Macro cases, largely reflecting rapid growth in ethylene production.

In total, end use demand for NGL rises 3.4 percent per year in the Current Tech case and 3.7 percent per year in both the High Tech and Alternative Macro cases over the projection period. Growth in primary demand is somewhat lower at 3.1 percent, 3.3 percent and 3.4 percent per year, in the three cases, respectively.

4.7.4   Primary Demand for Coal

The principal components of primary coal demand are: end use demand, use in the production of steam and electricity[40], own use, and conversion of coal into coke.

The majority of coal consumed in Canada is for the production of electricity, particularly in Alberta, Saskatchewan, Ontario and Nova Scotia (see Chapter 5). Coal used by the iron and steel industry for conversion to coke represents the second most important end use demand.

From 1991 to 2010 primary demand for coal increases at an average annual rate of 3 percent in the Current Tech case (Table 4-26). Coal used for electricity generation grows at an average annual rate of 2.9 percent from 914 petajoules in 1991 to 1 563 petajoules in 2010. Coal used for bitumen production is projected to increase in the Current Tech case after 2005 to 87.5 petajoules in 2010 (Table 4-26).

In the High Tech and Alternative Macro cases, lower natural gas prices result in significantly different coal demand profiles. Coal is not used for bitumen production in these cases as gas prices are below the threshold at which coal is competitive with natural gas in bitumen production. Furthermore, some coal-fired generation is displaced by gas-fired co-generation and utility combined-cycle plants. The electricity generation

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40   For further details regarding production of electricity using coal, see Chapters 5 and 9.

TABLE 4-25
Primary Demand for Natural Gas Liquids[1]
(Petajoules)

	1991	2010 Current Tech	2010 High Tech	2010 Alternative Macro
End Use Demand	243	462	480	485
Propane and Butanes	129	228	236	241
Ethane	114	234	244	244
Own Use and Conversions	82	96	96	96
Energy Supply Industry	3	6	6	6
Butanes Used for Blending	79	90	90	90
Sub-Total	325	558	576	581
Less Refinery LPG[2]	54	73	73	73
Primary Demand for Ethane and Gas Plant NGL	271	485	503	508

1   Excludes pentanes plus. Pentanes plus are included in crude oil.
2   End use demand assumed to be met by refineries.

profile is the same for High Tech and Alternative Macro cases, as utilities face the same relative fuel prices in each case. However, there is stronger growth in coal used for conversion to coke in the Alternative Macro case reflecting stronger growth in the Ontario steel industry. As a result, primary coal demand grows at an average annual rate of 2.2 percent in the High Tech case and 2.4 percent in the Alternative Macro case.

4.7.5 Primary Demand from Hydro and Nuclear Sources for Electricity Generation

Unlike other energy sources, hydro and nuclear are used solely in the production of electricity. Thus the demand for them is dependent on electricity demand and their relative competitiveness with other fuels used to produce electricity, primarily coal, natural gas and oil products (Table 4-27). The factors governing fuel choice by electric utilities for electricity generation are more fully discussed in Chapter 5.

In the Current Tech case, hydro generation increases at 1.4 percent per year during 1991-2010, somewhat more slowly than the 2.0 percent per year growth in electricity demand. Hydro and nuclear lose share to coal and natural gas. In the High Tech case, hydro's share is further reduced as lower gas prices encourage utilities to move towards gas-fired units. In the Alternative Macro case, hydro's share is assumed to be the same as the High Tech case, however, its demand level is higher because overall energy demand and the demand for electricity are higher.

Our analysis assumes no additional nuclear capacity, beyond current commitments, will be installed. However, higher utilization of existing facilities results in projected growth during 1991-2010 of 1.2 percent per year in the Current Tech and High Tech cases. In the Alternative Macro case higher electricity demand is shared among the primary fuels used for generation in the same proportions as the High Tech case.[41]

4.7.6 Total Primary Demand

Trends in future primary energy demand, by fuel type, are illustrated in Figure 4-32.

In the Current Tech case, Canadian primary energy demand is projected to grow at 1.7 percent per year during 1991-2010. Growth is slightly higher in the High Tech case at 1.9 percent per year but the fuel mix is quite different with gas improving its share against the other primary fuels as gas prices remain competitive. Interestingly, our analysis implies that, in a relatively stable energy price environment, energy demand tends to approach economic growth. In the Alternative Macro case, reflecting the more energy-intensive economy, energy demand growth is higher still at about 2.1 percent per year.

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41 Since the Alternative Macro case is a sensitivity on energy demand rather than a comprehensive case analyzed throughout this report, the implications of this case for electricity generation are not reviewed in Chapter 5. Primary energy demand is estimated using the fuel shares in electricity generation of the High Tech case.

TABLE 4-26
Primary Demand for Coal
(Petajoules)

	1971	1991	Current Tech	High Tech	Alternative Macro
			2010		
End Use Demand[1]	84	43	141	56	66
Electricity Generation[2]	387	914	1 563	1 376	1 415
Steam Generation	0	0	0	0	0
Other Conversions and Own Use	1	5	13	14	17
Coal to Coke Conversion	199	142	217	231	272
Primary Demand	671	1 104	1 934	1 677	1 769

1 Includes coke and coke oven gas.
2 Includes coal and orimulsion used for electricity exports.

4.8   CONCLUDING COMMENTS

Even with the detailed analysis in this report, we could not assess all areas of uncertainty for energy demand. We have focused our analysis on the impact of two factors – changes in natural gas supply costs (and therefore prices), reflecting variations in the rate of technological improvement, and potential changes in the structure of the economy between the goods and services sectors.

Our analysis indicates that energy demand and the fuel mix are sensitive to changes in these variables. In the High Tech case, lower natural gas prices have an impact on end use energy demand, leading to an increase of 425 petajoules over the Current Tech case by the end of the projection period. In the case of a relative shift in the industrial structure towards the goods sector in the Alternative Macro case, end use energy demand is an additional 565 petajoules higher than in the Current Tech case.

Naturally, these changes in assumptions have implications for fuel shares. Electricity demand grows faster than total energy demand in all three cases. Natural gas loses market share in the Current Tech case but gains market share in both the High Tech and Alternative Macro cases largely from HFO. The other fuels generally maintain market share.

Primary demand for natural gas accelerates in the High Tech case as demand from both electrical generation and bitumen production increase. Coal largely replaces use of natural gas in bitumen production in the Current Tech case because of its relative price advantage. Primary demand for oil loses market share to natural gas in both the High Tech and Alternative Macro cases.

There are two general trends which are apparent in all cases of our analysis. The first is that the rates of improvement in energy intensity which have occurred over the last two decades slow down over the next decade or so. This follows from our assumption that energy prices will increase relatively slowly over the projection period. Energy demand grows at somewhat more rapid rates than in past years, although the rate of growth varies

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TABLE 4-27

Primary Demand from Hydro, Nuclear and Other Fuels for Electricity Production

(Petajoules)	1991	2010 Current Tech	High Tech	Alternative Macro
Hydro	1 100	1 443	1 385	1 473
Nuclear	969	1 213	1 213	1 290
Coal	913	1 518	1 331	1 415
Natural Gas	76	245	537	570
Oil	130	172	175	187
Other	31	97	97	103
Total	3 219	4 688	4 738	5 038
(Fuel Share – Percent)				
Hydro	34	31	29	29
Nuclear	30	26	26	26
Coal	28	32	28	28
Natural Gas	3	5	11	11
Oil	4	4	4	4
Other[1]	1	2	2	2
Total	100	100	100	100

1   Includes alternatives and renewables, coke and orimulsion.
Source: Current Tech and High Tech, Table 5-17. The Alternative Macro case assumes the same fuel shares as the High Tech case.

from case to case. It is clear, however, that if energy prices were to rise more rapidly than we have assumed, overall energy demand would be less than projected.

The second trend is that demand for electricity increases as a result of ongoing developments of applications which are electricity-dependent. This has been occurring as computers, associated electronic devices, and other electrical appliances are increasingly used in both offices and homes. Nonetheless, growth in electricity demand will be affected by the overall rate of growth in economic activity and, to some extent, by the composition of this activity.

FIGURE 4-32
Primary Energy Demand by Fuel – Canada
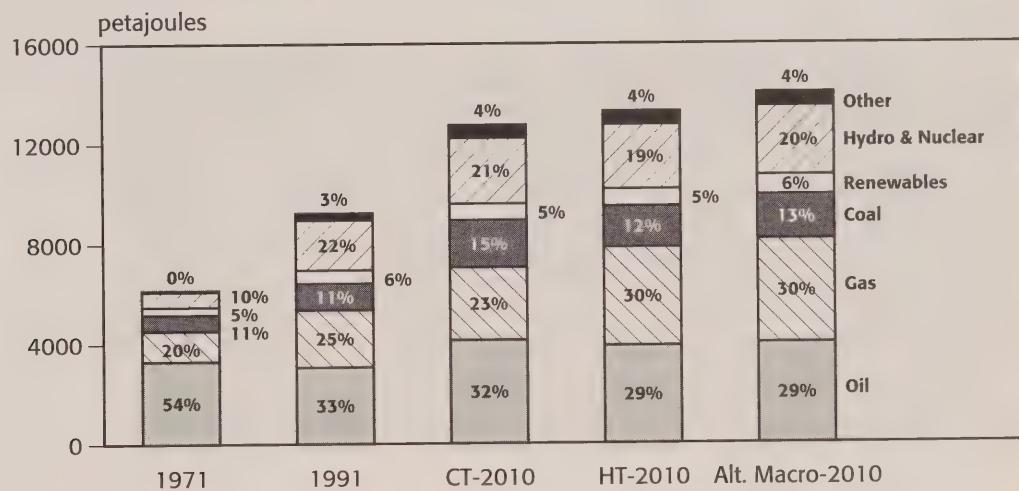
GOVERNMENT AND UTILITY SPONSORED PROGRAMS

In the 1970s and 1980s, a number of programs were developed by government and utilities designed to reduce the growth in energy demand through measures that promoted the use of energy efficient capital and energy conservation. Some of the programs focussed on reducing our reliance on oil by encouraging the use of natural gas, electricity, woodwastes and other fuels, in the residential, commercial, industrial and transportation sectors. A brief description of most of the major programs is described by sector in the following paragraphs.

Residential Sector

The following is a description of some of the programs that affected the demand for energy and fuel type in the residential sector:

- The Canadian Home Insulation Program (CHIP), first implemented in 1977 and in effect for ten years, was designed to improve the thermal efficiency of housing. CHIP provided grants to owners, landlords, and tenants to cover the costs of insulation materials for upgrading the pre-1977 housing stock.

- The R-2000 Home Program, established in 1980 by EMR Canada, was designed to encourage the construction of energy-efficient homes across Canada. A report based on the monitoring of this program between 1985 and 1987 of a sample of R-2000 homes indicated that although energy consumption for both water heating and space heating was below the program targets, consumption for lighting and appliances was 40 percent greater than predicted.

- The Canada Mortgage and Housing Corporation (CMHC) has helped in the construction of more energy-efficient housing by providing financial support for households to upgrade to or beyond provincial building code standards.

Various other federal, provincial and foreign government programs have acted to improve the energy efficiency of household appliances:

- The U.S. implemented the National Appliance Energy Conservation Act in March of 1987, which mandated a 10-30 percent improvement in the energy efficiency of major household appliances on the market in 1989.[42] Since most large appliances sold in Canada are either made here under American patents and designed to compete in the U.S. market or are imported from the U.S., the U.S. standards influence Canadian energy consumption.

- The Ontario Government legislated the Energy Efficiency Act in 1988 and the B.C. Government passed Bill 36 (Energy Efficiency Act) in 1990. These Acts set efficiency standards for energy using devices. Most of these new devices are manufactured according to the new standards.

- EMR Canada implemented in 1982 the Energuide Information Program, which was designed to help households choose the most energy efficient appliances for their homes.[43]

Other programs have been aimed at reducing the consumption of specific fuels:

- Demand Side Management (DSM) programs sponsored by utilities were designed to reduce electricity consumption. For example, electric utilities have implemented programs to educate consumers about electricity-saving opportunities and to provide them with financial incentives to undertake energy-efficiency improvements.[44]

- Hydro-Québec has encouraged households to install dual energy space heating systems, which use electricity as the main fuel source and a fossil fuel as a secondary source. Under the Hydro-Québec program, dual energy systems can only use electricity for space heating when the outdoor

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42 *The Most Energy-Efficient Appliances: 1989-90 Edition*, American Council for an Energy Efficient Economy, Washington, D.C., 1989.

43 *Energuide Directory 1992*, Energy, Mines, and Resources Canada, Ottawa, 1992. The program is still in effect.

44 Currently in Canada, electric utilities in all provinces except Northwest Territories and Yukon are committed to implementing DSM programs: natural gas utilities are preparing their own DSM programs. In the United States, DSM is being implemented by regulated utilities in a number of States as part of their Integrated Resource Planning programs.

temperature is at or above -12 C or -15 C (depending upon the climate zone); this is outside Hydro-Québec's seasonal peak period. Switching between the two fuel sources is controlled automatically by Hydro-Québec's outdoor temperature meter. Households save on their total energy bills by avoiding the use of electricity during the period when the outdoor temperature is at or below -12 C or -15 C since Hydro Québec offers them a lower rate for their off-peak use.

- The Canadian Oil Substitution Program (COSP) was implemented in 1981 to encourage Canadian households to switch from oil to other fuels as a source for space heating. This program was motivated by government concern over the security of oil supply. COSP encouraged approximately 1.2 million off-oil conversions in Canada between the time of implementation and its conclusion in March 1985. Almost half of these conversions occurred in Québec, where lower electricity prices made off-oil conversion more economically attractive than in some other regions. The fewest conversions occurred in Alberta, where the main source of space heating was already natural gas.

Commercial Sector

The following is a description of some of the programs that affected the demand for energy and fuel type in the commercial sector:

- The joint federal-provincial National Energy Audit Program (NEAP) was one of the first energy programs. It was implemented in 1980 to provide on-site analysis of energy use and assistance in implementing measures to improve energy efficiency. The Forest Industry Renewable Energy (FIRE) program became operational in 1982. It provided grants to commercial and institutional organizations who were willing to use renewable resources, such as wood and municipal waste, as an energy source. In 1987, Hydro-Québec designed and implemented a program that provided grants to organizations who were willing to use a dual-energy heating system, where Hydro-Québec electricity was the main fuel source and a fossil fuel was the secondary source of fuel.[45] Currently, the Federal Buildings Initiative (FBI) is being implemented by the federal government. The goal of the program is to improve the energy efficiency of space and hot water heating, lighting and ventilation in all federal government-owned facilities.

Demand Side Management programs designed to shape and reduce the demand for electricity are currently sponsored by some electric utilities. DSM programs include the provision of financial incentives for the installation of more energy-efficient equipment, the promotion of overall energy conservation through information media and programs aimed at reducing seasonal or daily peaks.

Industrial Sector

The following is a description of some of the programs that affected the demand for energy and fuel type in the industrial sector:[46]

- Class 34 Accelerated Capital Cost Allowance: this is a federal tax initiative, implemented in 1976 and still in effect. It allows an accelerated rate of depreciation for tax purposes for investment in more energy efficient electricity-generating or steam-raising capital equipment, and in processes that use renewable forms of energy.[46]

- National Energy Audit Program (NEAP): NEAP was a federal government program in effect from 1980 to 1985. The initiative provided free on-site energy audits to identify potential sources of energy savings and energy efficiency improvements. Grants were also provided under the program to cover the costs of planning and implementing the identified energy efficiency improvements.

- Atlantic Energy Conservation Investment Program (AECIP): AECIP was a joint program of the

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44 This program was called the "Grant Program for Installation of Dual-Energy Heating in Institutional, Industrial and Commercial Buildings". It is similar to the Hydro-Québec program for the residential sector described earlier. As with that program, one of the stipulations of the program was that Hydro-Québec have the ability to automatically control switching between the two fuel sources.

45 Evaluations of the many federal government programs that were initiated during the late 1970s and early 1980s suggest that these programs had their most pronounced effect on the residential sector, followed by the commercial sector with the smallest impact occurring in the industrial sector. Of the $1.4 billion allocated as federal government financial incentives for energy conservation and substitution over the 1973 to 1987 period, more than 90 percent of the funds were directed toward the residential and commercial sectors (see "Energy Demand in Canada, 1973 -1987: A Retrospective Analysis", Volume I, consultation report prepared by Marbek Resource Consultants for Energy Mines and Resources Canada, March 1989).

46 More energy efficient capital is deemed to be capital that has been certified by Energy Mines and Resources, now Natural Resources Canada, as representing a quantifiable reduction in the use of energy per unit of output.

federal government and the provincial governments of the Atlantic region over the period 1981 to 1985. It offered capital grants to firms to convert existing facilities to more energy efficient capital in order to reduce the need for imported oil. An evaluation of this program indicates that it did have some small effect at the margin on firms investment decisions but that it did not in itself significantly affect energy consumption patterns in the Atlantic region. Its effectiveness was reduced by two factors: the 1981-82 recession and the flattening in oil prices toward the end of the program.[48]

- Forest Industry Renewable Energy (FIRE): the FIRE program, from 1978 to 1984, was intended to encourage the substitution of wood wastes and other biomass for fossil fuels in the pulp and paper and forestry industries. Evaluations of this program indicate that it had very little incremental effect on the fuel use decisions of firms in these two industries since they were already substituting readily available (and free) on-site wood wastes for petroleum products.

- Electro-Technology Implementation Assistance Program: this program was begun by Hydro-Québec in 1985 and will continue until 1996. It is aimed specifically at increasing the use of electricity in industrial applications in the province of Québec through the use of grants that will substitute electricity using capital/applications for fossil fuel using capital/applications. Evaluations of this program to date indicate that it has had some effect on fuel use by small and medium size industrial users but has not had a significant overall impact on electricity use within the Québec industrial sector.

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48 *Energy Demand in Canada, 1973-1987: A Retrospective Analysis*, Volume I, prepared by Marbek Resource Consultants for Energy Mines and Resources Canada, March 1989.

Chapter 5

ELECTRICITY

5.1   INTRODUCTION

The principal objective of this chapter is to provide an outlook of primary energy requirements for the supply of electricity in Canada to meet domestic loads and electricity exports during the period from 1991 to 2010.

Three separate cases are examined. The first two cases correspond to the Current Tech and High Tech cases that are addressed throughout this report. These two cases focus on the implications of different gas price profiles on electricity supply and on the resulting demands for fuels for electricity generation. In the High Tech case, gas prices rise less rapidly than in the Current Tech case because of increased efficiencies and the availability of new technologies in the exploration, development and production of natural gas. Since natural gas is generally not available east of Québec, there is no difference between these two cases in the Atlantic provinces. The relatively small quantities of natural gas that are expected to be available from offshore Nova Scotia late in the study period were not factored into the analysis of electricity supply. In both the Current Tech and High Tech cases it was assumed that generation planning would continue to be performed on an individual provincial basis.

In the third case, the Enhanced Cooperation case, it was assumed that generation planning would be conducted on a regional, rather than a provincial basis, where there appeared to be economic advantages in doing so. In this case, a considerably greater degree of inter-utility cooperation would be necessary than exists today. An inherent requirement of this case is that there would be open access to transmission networks. For the purposes of this analysis, the gas price profile that corresponds to the Current Tech case was used in the Enhanced Cooperation case.

Section 5.2 in this chapter provides background to the changing nature of the electricity supply industry in Canada. Section 5.3 describes the derivation of annual electrical energy and peak demand projections for each province. Section 5.4 summarizes the assumptions made concerning firm trade between Canada and the U.S. and among provinces. Existing generating resources, and the development of generation expansion programs for each province in the Current Tech and High Tech cases are discussed in Section 5.5.

Section 5.5 also contains projections of annual generation in each province. Estimates of interruptible and resulting total trade, both interprovincial and international, corresponding to the Current Tech and High Tech cases, are presented in Section 5.6. Generation expansion programs, estimates of electricity trade, and annual electricity production for the Enhanced Cooperation case are contained in Section 5.7. Section 5.8 provides a summary of the supply and demand of electricity in Canada, while Section 5.9 contains corresponding projections of primary energy demand for electricity production.

5.2   BACKGROUND

The electricity supply industry in Canada and in many other countries is undergoing substantial changes that are unprecedented in the industry's history. Utilities are being restructured; one long-established provincially-owned utility has been privatized; consideration is being given in some jurisdictions to unbundling the principal electricity supply functions of generation, transmission and distribution; some industrial and municipal electricity purchasers are uneasy at their "captive customer" status; and utilities are facing increasing competition from non-utility generators (NUGs).

In order to permit increased and wider competition among generators, utilities and NUGs typically require access to transmission networks owned by others, and, in several countries, legislation has been enacted to facilitate such access. For example, in 1992, the U.S. Congress passed the Energy Policy Act which obligates transmission owners to provide non-discriminatory access to others.

Access to transmission networks and increased competition in the supply of electricity are leading to the development of power exchanges and the emergence of power aggregators and brokers. Also, it is resulting in electricity markets becoming more short-term in nature. There is less demand for firm power contracted between utilities on a long-term basis. Instead, utilities are being invited to bid, often at short notice, to supply short-term power. Another factor that has contributed to declining opportunities for long-term firm trade is that many regions in North America are experiencing capacity surpluses brought about by the development of new

generation projects to meet forecasted loads that have not materialized.

Consequently, Canadian utilities that have traditionally sold power in the U.S. are having to adjust their ways of doing business. For example, BC Hydro has established a power exchange (POWEREX) to market power from British Columbia, as well as power flowing through the province, in the U.S. Also, Alberta and B.C. are cooperating by using surplus low-cost, coal-fired generation in Alberta during off-peak periods to displace hydroelectric production in B.C. and thereby to store water in BC Hydro's reservoirs. The stored water is then used to generate during peak load periods to displace higher-cost production in Alberta and elsewhere. There may be similar opportunities to make use of hydro storage reservoirs in other Canadian provinces and thus contribute to expanding interprovincial and international electricity trade.

Utilities are beginning to engage in more regional generation and transmission planning. The objective of such planning is to develop and/or operate generation resources to supply power at least cost and with minimum social and environmental impacts over wider geographical areas. That is, low-cost generating projects located in one jurisdiction would be built and operated to supply loads in other jurisdictions where generating costs are higher.

With the passage of the U.S. Energy Policy Act, power producers in the U.S. are being encouraged by the Federal Energy Regulatory Commission (FERC) to form Regional Transmission Groups (RTGs) in which transmission-owning members would provide access to their networks by others. Some Canadian utilities are actively considering becoming members of these organizations.

If Canadian utilities elect to join RTGs, electricity trade between Canada and the U.S. could be expected to be greater than it would otherwise be. However, this potential trend is not reflected in the current study because of the general assumption made that new generating facilities would not be built in Canada during the study period to supply firm loads in the U.S. Moreover, potential electricity transactions like those described above involving the use of hydroelectric storage reservoirs are not captured in the Board's analysis.

Most utilities are currently engaged in promoting demand-side management (DSM) programs. Existing and planned utility DSM programs, for both energy conservation and peak load reduction, were taken into account in this study. An extension of these activities is

for utilities to engage in integrated resource planning (IRP) in which both traditional and alternative supply-side resources can be compared with demand-side programs in deciding on the most efficient and effective means of providing electricity services. The social and environmental impacts of electricity generation can be incorporated into the comparison. BC Hydro has begun to adopt a costing methodology that includes allowances for these external impacts in its comparison of costs of resource alternatives. Thus, the nature of the generation planning process is expanding. The analysis conducted in this study did not attempt to integrate environmental and social costs into the selection of generation additions.

5.3   DOMESTIC ELECTRICITY DEMAND

Table 5-1 presents the actual total provincial and territorial electrical energy demands as reported to Statistics Canada in 1991, together with the Board's energy demand projections for the year 2010, corresponding to both the Current Tech and High Tech cases. The energy demand figures given in the table take into account the effects of utility demand-side management programs and system losses.

As discussed in Chapter 4, the Board's projections of electrical energy demands were prepared in conjunction with demand estimates for other energy commodities, using a common set of macroeconomic parameters. This approach ensures consistency, both geographically and among the demands for all energy products in the Canadian economy as a whole. The detailed methodology and the macroeconomic assumptions that were used to derive the projections of energy demand are presented in Chapters 2 and 4.

The provincial domestic energy demand projections given in Table 5-1 were adjusted to account for estimated energy loads of self-generators and minor utilities to obtain domestic energy loads to be met by major utilities. Major utility domestic peak demands were derived from corresponding energy demands by applying the appropriate annual system load factors, which are usually provided in the utilities' published load forecasts. Estimated peak demands by self-generators and minor utilities were then added to give total provincial domestic peak demands, and these values are also shown in Table 5-1.

Total domestic energy demand in Canada in 1991 was 474.6 terawatt hours. The Board projects that, by 2010, this will grow to 686.5 terawatt hours in the Current Tech case and to 689.4 terawatt hours in the High Tech case. In both cases, the average annual

TABLE 5-1

TABLE 5-1

Domestic Energy and Peak Demand for Electricity by Province and Territory[1]

	Energy Demand[2] (gigawatt hours)			Average Growth Rate (percent/annum)		
	1991[3]	**Current Tech 2010**	**High Tech 2010**	**Current Tech**	**High Tech**
				1991 to 2010	
Newfoundland and Labrador	10 576	14 170	14 170	1.6	1.6
Prince Edward Island	761	1 218	1 218	2.5	2.5
Nova Scotia	9 776	12 882	12 882	1.5	1.5
New Brunswick	13 699	18 325	18 325	1.5	1.5
Québec	161 530	237 247	237 888	2.0	2.1
Ontario	143 460	202 389	203 379	1.8	1.9
Manitoba	18 019	24 590	24 751	1.6	1.7
Saskatchewan	13 847	18 623	18 794	1.6	1.6
Alberta	44 185	68 615	69 073	2.3	2.4
British Columbia	57 711	87 192	87 615	2.2	2.2
Yukon	461	509	509	0.5	0.5
Northwest Territories	571	755	755	1.5	1.5
Canada	**474 596**	**686 515**	**689 359**	**2.0**	**2.0**

	Peak Demand[4] (megawatts)			Average Growth Rate (percent/annum)		
	1991[5]	**Current Tech 2010**	**High Tech 2010**	**Current Tech**	**High Tech**
				1991 to 2010	
Newfoundland and Labrador	1 931	2 874	2 874	2.1	2.1
Prince Edward Island	137	198	198	2.0	2.0
Nova Scotia	1 858	2 347	2 347	1.2	1.2
New Brunswick	2 906	3 763	3 763	1.4	1.4
Québec	33 637	47 097	47 227	1.8	1.8
Ontario	24 008	32 581	32 739	1.6	1.6
Manitoba	3 493	4 651	4 681	1.5	1.6
Saskatchewan	2 338	3 106	3 135	1.5	1.6
Alberta	6 703	10 448	10 517	2.4	2.4
British Columbia	9 456	15 319	15 396	2.6	2.6
Yukon	88	100	100	0.7	0.7
Northwest Territories	108	141	141	1.4	1.4
Canada	**86 663**	**122 625**	**123 118**	**1.8**	**1.9**

Notes: The numbers in this table have been rounded.

1   Domestic energy demands include major utility, minor utility and self-generator domestic loads.

2   Derived from corresponding end-use petajoule demands described in Chapter 4 using a conversion factor of 0.0036 peta-joules per gigawatt hour, and adjusted for system losses. Figures represent total provincial energy demands after subtract-ing energy conservation programs.

3   Source: Statistics Canada Cat. 57-202 for 1991.

4   Peak demands are the sum of non-coincident peak loads in each service area and therefore overstate the actual peaks. Figures respresent total domestic peak demands before subtracting interruptible load programs.

5   Source: Statistics Canada Cat. 57-206 for 1991 and consultations with utilities.

growth rate is approximately 2.0 percent. Domestic peak demand increases at a slightly lower rate than does energy demand because of general increases in system load factors.

5.4   FIRM TRADE

All adjacent provincial electricity transmission networks are interconnected. Also, apart from Alberta, all provinces that border the U.S. have transmission links to neighbouring U.S. systems. These interconnections allow electricity trade to take place. Trade between two systems is beneficial when the contemporaneous supply costs in the two areas differ. Therefore, the exploitation of trade opportunities reduces the overall cost of electricity within trading regions.

Electricity trade can be divided into firm trade and interruptible trade. Firm trade tends to be relatively long-term in nature and can involve the development of new generation and/or transmission facilities. Therefore, it can affect utilities' generation expansion programs. On the other hand, interruptible trade is used primarily to optimize the relatively short-term operation of two or more interconnected systems, and does not involve major expansion of facilities.

This section outlines the firm trade assumptions made in the current analysis corresponding to average hydrological conditions. Interruptible trade is discussed in Section 5.6.

Many utilities, both in Canada and the U.S., currently have excess generating capacity. Moreover, there is a growing trend in the electric power industry to avoid the financial risks associated with long-term contracts. Also, with the opening up of more competitive markets for electricity in North America, more trade is being conducted on a short-term basis.

The Board's projections of firm trade are based on actual long-term contract data, information provided by the utilities, in-house historical records, and the Board's judgement of future potential for this form of trade. It was assumed that, during the study period, no new generating facilities would be developed in Canada to supply firm loads in the U.S.

The firm international and interprovincial transactions described below are those assumed to apply to the Current Tech and High Tech cases, and except where noted, to the Enhanced Cooperation case.

5.4.1   Firm International Trade

Major firm exports to the U.S. North American Electric Reliability Council (NERC) regions or power pool areas, that were assumed in the analysis for the period 1994 to 2010 are:

- unit participation sales of 50 megawatts and 394 gigawatt hours per annum from NB Power's Point Lepreau unit 1 to the New England Power Pool (NEPOOL);

- sales of 362 megawatts and 2 400 gigawatt hours per annum, and sales of 3 975 gigawatt hours per annum from Hydro-Québec to NEPOOL;

- sales of 500 megawatts and 3 616 gigawatt hours per annum from 1994 to 2004, and 485 gigawatt hours per annum throughout the study period from Manitoba Hydro to the Mid-Continent Area Power Pool (MAPP) region;

- back-to-back energy sales of 946 gigawatt hours in 1994 and 552 gigawatt hours in 1995 from Alberta utilities through B.C. to the Western Systems Coordinating Council (WSCC) region; and

- sales ranging from 124 megawatts and 681 gigawatt hours to 324 megawatts and 1 575 gigawatt hours from BC Hydro to the WSCC region.

For most provinces, under average hydroelectric production conditions, firm electricity imports from the U.S. are projected to be relatively small over the study period, except in B.C., where imports associated with the Columbia River Treaty could be quite substantial. Under the terms of the Treaty, which was signed in 1964, the Province of British Columbia is entitled to receive electrical capacity and energy benefits from the U.S. in return for streamflow regulation provided by three reservoirs on the Columbia River in Canada. The U.S. rights to these benefits begin to expire in 1998. After that time, B.C. has the option to continue selling these benefits in the U.S., or to have them returned to B.C. in the form of capacity and energy[1]. The actual amounts of capacity and energy available to B.C. from this source will depend on load growth in the U.S. Pacific Northwest (PNW) and on the new resources developed to serve it. In the Current Tech and High Tech cases, the benefits were assumed to be returned to B.C. Assuming medium load conditions in the PNW, the amounts of these benefits would be 435 gigawatt hours and 120 megawatts in 1998, increasing to 4 665 gigawatt hours and

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1   Since the time the Board's analysis was completed, the Province of British Columbia has decided to continue selling these benefits to the U.S.

1 340 megawatts by 2003, and then gradually changing to 4 483 gigawatt hours and 1 350 megawatts by 2010. In the Enhanced Cooperation case it was assumed that B.C. would continue to sell these benefits in the U.S., and as a result, imports to B.C. become zero.

Other major firm import commitments that were assumed during the study period are:

- purchases by Hydro-Québec from NEPOOL of 50 megawatts and 300 gigawatt hours per annum ending in 1996, and purchases of 25 megawatts and 200 gigawatt hours per annum for the entire period;

- a capacity purchase by Hydro-Québec of 400 megawatts from the New York Power Authority for the entire period; and

- a capacity purchase by Manitoba Hydro from the MAPP region of 300 megawatts in 1995, and increasing to 500 megawatts in subsequent years, for winter peaking purposes.

5.4.2 Firm Interprovincial Trade

Except for the firm sale from the Churchill Falls hydroelectric project in Labrador to Québec, most interprovincial trade is composed of interruptible energy transfers. This is due to the fact that Canadian utilities tend to satisfy domestic load growth by developing generating resources located within their own provinces, which results in very little need for major firm interprovincial transfers.

Major firm interprovincial transactions that were included in the current analysis for the period 1994 to 2010 are:

- long-term sales of 4 903 megawatts and 30 164 gigawatt hours per annum under average hydroelectric production conditions from Labrador to Québec;

- unit participation sales of 19 megawatts and approximately 135 gigawatt hours per annum from NB Power's Dalhousie unit 2, and a further unit participation sale of 19 megawatts and 149 gigawatt hours per annum from NB Power's Point Lepreau unit 1, to Maritime Electric Company, Limited (MECL) in Prince Edward Island. After 1994, it was assumed that MECL would increase its participation in the Point Lepreau unit to 24 megawatts and 189 gigawatt hours per annum;

- firm capacity sales of 400, 300 and 200 megawatts from NB Power's Millbank plant to Hydro-Québec

in the periods 1991 to 1997, 1998 to 2001 and 2002 to 2010, respectively;

- sales of 56 megawatts and 490 gigawatt hours per annum from Hydro-Québec to Ontario Hydro until 1999; and

- sales from Manitoba Hydro to Ontario Hydro of 200 megawatts and varying amounts of energy from 1998 to 2003, and 145 gigawatt hours per annum of energy throughout the study period.

A number of additional firm interprovincial electricity transactions were assumed in the Enhanced Cooperation case. As mentioned previously, the Enhanced Cooperation case assumes that generation planning would be conducted on a regional rather than on a provincial basis in order to reduce the overall cost of electricity production. Assumptions and further details regarding the Enhanced Cooperation case are provided in Section 5.7.

5.5 GENERATING CAPACITY AND ELECTRICAL ENERGY PRODUCTION

The total existing generating capacity and recorded electrical energy production in each province and territory in 1991 are presented in Table 5-2. The values given for Newfoundland and Labrador include the capacity and energy generation at the Churchill Falls hydroelectric project, most of which is sold under long-term contract to Hydro-Québec. Total installed net capacity in Canada in 1991 was just over 102 gigawatts and total electricity generation was 493 terawatt hours.

For each province and territory, major utility generation expansion programs were developed which, together with existing generating resources, are capable of reliably meeting projected major utility system firm energy and peak loads. Major utility system firm loads were computed from total provincial domestic loads, as described in Section 5.3, by adjusting for net external firm sales, and for loads met by minor utilities and non-utility generators. Further adjustments were made to peak demands to account for major utility interruptible load programs.

An inventory of existing major utility generating units was prepared from data collected and compiled by Statistics Canada. Information on committed new generating units and existing units scheduled for retirement was obtained from the utilities or from data published by the provinces.

Potential new generating sources were identified in each province, and the levelized unit cost of generation

from each source was computed for a range of capacity factors using estimates of capital and operating costs, unit heat rate and fuel prices over its economic life. Capital and operating cost estimates and heat rates for projects under consideration were obtained either directly from the utilities or from the Board's database. Fuel prices were taken from the Board's own projections as described in Chapter 3.

The analysis of unit costs of generation indicated that, in general, hydropower is the least-costly source of new major base-load generation in Labrador, Québec, Manitoba and B.C., and that base-load thermal generation is least-costly on the Island of Newfoundland, and in the Maritimes, Ontario, Saskatchewan and Alberta.

In the Current Tech case, the estimated unit costs of base-load gas-fired generation are substantially higher than those of alternative hydro and coal-fired projects. In the High Tech case, in which gas prices are less than in the Current Tech case, the costs of base-load gas-fired generation remain generally higher than the alternatives, but the differences are much smaller.

In selecting generation additions, utilities take into consideration a large number of factors including the levelized unit cost of power from each alternative available, environmental and social impacts, financial and fuel price risks, rate impacts, fuel diversity and security, planning and operating flexibility, etc. Generation expansion programs developed in this study were guided by factors such as utility preferences, provincial polices, estimated levelized unit costs, and regulations covering gaseous emissions from power plants.

New hydroelectric projects tended to be selected in the Current Tech case to supply load growth in the hydro-rich provinces, while base-load coal-fired units were preferred in most other provinces. However, gas-fired capacity requires less capital investment than the alternatives, has a relatively short lead time, is more efficient than coal-fired units, and tends to have fewer environmental and social impacts. Therefore, in the High Tech case, it was assumed that these factors would outweigh the higher power costs associated with base-load gas-fired generation and that gas-fired combined cycle capacity would be installed to displace all or some of the new hydro or coal-fired units that were included in the Current Tech case.

Annual capacity and energy load-resource balances were carried out for each major utility system to determine the timing of generation additions required to

TABLE 5-2

Generating Capacity and Energy Production by Province and Territory – 1991

	Capacity[1]		Energy[2]	
	Megawatts	**Percent**	**Gigawatt Hours**	**Percent**
Newfoundland and Labrador	7 357	7.2	36 977	7.5
Prince Edward Island	116	0.1	71	0.0
Nova Scotia	2 172	2.1	9 394	1.9
New Brunswick	3 859	3.8	15 807	3.2
Québec	30 275	29.6	142 992	29.0
Ontario	31 191	30.5	142 441	28.9
Manitoba	4 848	4.7	22 891	4.6
Saskatchewan	2 707	2.6	13 598	2.8
Alberta	7 973	7.8	44 481	9.0
British Columbia	11 588	11.3	63 374	12.9
Yukon	128	0.1	461	0.1
Northwest Territories	190	0.2	571	0.1
Canada	**102 404**	**100.0**	**493 058**	**100.0**

Notes: The numbers in this table have been rounded.

1 Represents installed net dependable capacity. Source: Statistics Canada Cat. 57-206 for 1991 and consultations with utilities.

2 Represents domestic energy production. Source: Statistics Canada Cat. 57-202 for 1991.

meet corresponding firm peak and energy loads and reserve requirements throughout the study period.

An in-house computer model was then used to determine the amount of annual generation by each thermal unit available to the major utility system, assuming average energy production conditions at hydroelectric plants. The model operates using an annual time interval and employs an economic unit dispatch technique with the objective of minimizing total thermal fuel costs.

In each province, generation that is surplus to domestic and firm transfer requirements was computed for each year of the study period. Annual interruptible power transactions among the provinces, and between Canada and the U.S. were estimated taking into consideration these surpluses, their estimated incremental short-run marginal generating (fuel) costs, interconnection capabilities between systems and historical transfer levels.

The economic unit dispatch model was then re-run for each province to include all estimated interruptible transfers in order to obtain total electricity generation and primary fuel requirements for the major utilities.

Finally, national- and provincial-level projections of total electricity generation and primary fuel demands were derived by summing the components that make up these totals. These components include projections for the major utilities, as described above, as well as the minor utilities and industrial self-generators.

The following sections present an overview of the major inputs and assumptions that were used in the analysis for each province and territory for both the Current Tech and High Tech cases. Brief discussions of the results are also provided.

Tables 5-3 to 5-14 present the Board's projections of total provincial and territorial electrical energy production, and major utility firm capacity for the Current Tech case for the years 1991, 2000 and 2010. More detailed presentations of generating capacity and energy production estimates, at the provincial level, for both the Current Tech and High Tech cases are contained in Appendix Tables A5-1 and A5-2, respectively.

5.5.1 Newfoundland and Labrador

The Board projects that total provincial electrical energy demand in Newfoundland and Labrador will grow from 10 576 gigawatt hours in 1991 to 14 170 gigawatt hours in 2010, corresponding to an average annual growth rate of 1.6 percent.

Total electricity loads of the two major utilities on the Island of Newfoundland in 1991 were 6 701 gigawatt hours and 1 278 megawatts. In its 1993 forecast, Newfoundland and Labrador Hydro (N&LH) estimates that, by 2010, total loads on the island will have increased at an average annual growth rate of 1.5 percent to 8 912 gigawatt hours and 1922 megawatts. The Board projects that the average growth of electricity loads on the island will be considerably higher, at 2.2 percent per annum, reaching 10 105 gigawatt hours and 2 179 megawatts by 2010. The difference in the two projections has a significant impact on the requirements for new generating capacity over the study period.

In 1991, utility-owned generating capacity on the island totalled 1 675 megawatts, comprising primarily hydroelectric and oil-fired steam units. Pending regulatory approval, Newfoundland Light & Power is planning to install a 6 megawatt small hydro plant at Rose Blanche Brook in 1995. Also, it is expected that N&LH will purchase approximately 45 megawatts of independent power producer (IPP) capacity from several small hydro projects in 1997, followed by a 50 megawatt biomass steam project in 2000. In addition, it was assumed that a 15 megawatt small hydro IPP project would be commissioned in 2010.

Alternatives available for additional base-load generating capacity include the development of small and medium-sized hydroelectric projects; installing oil-fired combustion turbines at the St. John's generating station in order to upgrade the existing steam unit to combined cycle; adding an oil-fired steam unit at the Holyrood plant; developing a new oil-fired combined cycle unit; and, if major hydroelectric development takes place on the Lower Churchill River in Labrador, transferring power from that source through a new submarine cable to the island.

Assuming the Board's load projection, the island system will require an additional 250 megawatts of peaking capacity between 1996 and 2008. This capacity was assumed to be supplied by oil-fired combustion turbines. Additional energy-producing capability is required by 1997. To meet this demand, a 70 megawatt combined cycle upgrade to the St. John's plant, as well as a new 75 megawatt oil-fired combined cycle block were assumed to be installed in that year. This is the only type of plant that could be installed in the required time frame. To meet the projections of the Board requires that a total of 79 megawatts of hydro capacity be installed between 2000 and 2010, followed by an additional 143 megawatt oil-fired steam unit that would be commissioned in 2003.

If the utility's (lower) load forecast were to materialize, the additional 75 megawatts of

combined cycle, 79 megawatts of hydro, and 100 megawatts of combustion turbine capacity could be eliminated. Also, the timing of the other generation additions would be adjusted.

Labrador's share of the province's total electricity demand in 1991 was approximately 25 percent. Information provided by N&LH indicates that Labrador's loads are forecast to grow at an average rate of 0.4 percent per annum over the study period.

The capacity available in Labrador in 1991 to supply domestic loads was 555 megawatts. N&LH commissioned 27 megawatts of oil-fired combustion turbine capacity in 1992.

While electricity demand in Labrador represents only one quarter of the total provincial demand, approximately 77 percent of the province's total electricity generating capacity is located in Labrador, primarily at the Churchill Falls hydroelectric facility. Although, most of the output from Churchill Falls is sold under a long-term contract to Québec, the contract allows for a certain portion of the plant output to be retained, or recalled, to serve local loads. Given the forecast of low load growth, it is estimated that the recalled output from Churchill Falls, combined with existing thermal generating facilities, will be sufficient to satisfy Labrador's electricity needs until after 2010.

5.5.2 Prince Edward Island

Electrical energy demand in Prince Edward Island (P.E.I.) is projected by the Board to increase from 761 gigawatt hours in 1991 to 1 218 gigawatt hours in 2010, which is equivalent to an average annual growth rate of 2.5 percent. This projection is almost identical to the forecast developed by Maritime Electric Company, Limited (MECL) in 1993.

To satisfy this demand, MECL currently has a total available generating capacity of 148 megawatts which includes 105 megawatts of on-island oil-fired generation, as well as participation in NB Power's Point Lepreau nuclear unit and Dalhousie unit 2 at 19 megawatts each, and a short-term 5 megawatt capacity purchase from Hydro-Québec. Electricity is transferred from the mainland to the island through submarine cables which were installed in the 1970s. The cables were recently upgraded to provide a total transfer capability of approximately 200 megawatts. An interconnection agreement with NB Power allows MECL to use the cables to offset the high cost of production at on-island generation facilities, which use imported oil, by purchasing most of P.E.I.'s electricity needs from the mainland.

Existing on-island generating capacity is relatively old and it is expected that, rather than retire the units, MECL will probably undertake life extension work on some of them during the study period. However, it was assumed that Charlottetown unit 5 would be retired in 1998.

It was also assumed that MECL would negotiate an increase in its participation share in the Point Lepreau unit to 24 megawatts beginning in 1995, and that this would continue for the remainder of the study period.

Under the terms of its interconnection agreement with NB Power, MECL is required to maintain capacity equivalent to its firm peak load plus a 15 percent reserve margin. Two options that are available to MECL to meet this requirement are to upgrade the existing oil-fired steam units 7 and 8 at the Charlottetown plant to combined cycle units, and to purchase additional firm capacity from the mainland. For the purposes of this study, the combined cycle upgrades at Charlottetown were assumed to take place in 1997 and 2003, adding a total of 54 megawatts to on-island generating capacity. It is expected that P.E.I. will continue to import most of its electrical energy requirements from the mainland.

5.5.3 Nova Scotia

It is anticipated that provincial demand for electrical energy in Nova Scotia will increase at an average annual rate of 1.5 percent from 9 776 gigawatt hours in 1991 to 12 882 gigawatt hours in 2010.

The Board projects that the major utility firm demand for electricity in the province will grow at an average annual rate of 1.5 percent from 9 398 gigawatt hours and 1 645 megawatts in 1991 to 12 519 gigawatt hours and 2 052 megawatts by 2010. This outlook is very similar to the 1993 forecast developed by Nova Scotia Power Inc. (NSPI), which indicates loads in 2010 of 12 977 gigawatt hours and 2 136 megawatts.

In 1991, the utility-owned installed capacity in Nova Scotia was 2 119 megawatts, of which approximately 55 percent is coal-fired. The remaining capacity is composed of a mix of diesel units, heavy fuel oil-fired steam units and hydroelectric projects.

In 1993, NSPI commissioned the 165 megawatt coal-fired steam unit 1 at Point Aconi. This unit uses circulating fluidized bed technology and is the first generating unit of its kind in Canada. Soon after the commissioning of Point Aconi, NSPI mothballed two 20 megawatt coal-fired units at Trenton. The utility decided it was more economic to defer the capital expenditures required to keep these units operating until that time when additional capacity is required and when the expenditures could be justified.

TABLE 5-3

Supply and Demand of Electricity in Newfoundland and Labrador

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**10 576**	**12 719**	**14 170**
of which - Major Utility Demand	9 271	11 430	12 881
- Other Demand	1 305	1 289	1 289
External Sales[2]	**26 401**	**31 849**	**31 788**
Total Demand	**36 977**	**44 568**	**45 958**
Major Utility Generation	**35 640**	**42 720**	**44 045**
of which: - Hydro[3]	34 107	39 138	39 533
- Coal	0	0	0
- Nuclear	0	0	0
- Other[4]	1 533	3 582	4 512
Industrial and Minor Utility Generation	**1 337**	**1 321**	**1 321**
Independent Power Production	**0**	**527**	**592**
External Purchases[2]	**0**	**0**	**0**
Total Supply	**36 977**	**44 568**	**45 958**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**1 707**	**2 297**	**2 650**
Firm External Sales	**4 903**	**4 903**	**4 903**
Interruptible loads	**0**	**100**	**150**
System Firm Peak Demand	**6 610**	**7 100**	**7 403**
Major Utility Generating Capacity[5]	**7 133**	**7 512**	**7 753**
of which: - Hydro[3]	6 390	6 427	6 475
- Coal	0	0	0
- Nuclear	0	0	0
- Other[4]	743	1 085	1 278
Incremental Capacity Commissioned		409	241
of which: - Hydro[3]		37	48
- Coal		0	0
- Nuclear		0	0
- Other[4]		372	193
Incremental Capacity Decommissioned		30	0
of which: - Hydro[3]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[4]		30	0
Independent Power Producer Capacity[5]	**0**	**95**	**110**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utilities	**7 133**	**7 607**	**7 863**

Notes: Numbers in this table have been rounded.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial transactions, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes fuel oils and biomass.
5   Represents installed net dependable capacity.

TABLE 5-4
Supply and Demand of Electricity in Prince Edward Island

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	761	955	1 218
of which - Major Utility Demand	761	955	1 218
- Other Demand	0	0	0
External Sales[2]	**0**	**0**	**0**
Total Demand	**761**	**955**	**1 218**
Major Utility Generation	71	87	88
of which: - Hydro	0	0	0
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	71	87	88
Industrial and Minor Utility Generation	**0**	**0**	**0**
Independent Power Production	**0**	**0**	**0**
External Purchases[2]	690	868	1 130
Total Supply	**761**	**955**	**1 218**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	137	161	198
Firm External Sales	0	0	0
Interruptible loads	18	20	20
System Firm Peak Demand	119	141	178
Major Utility Generating Capacity[4]	105	126	156
of which: - Hydro	0	0	0
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	105	126	156
Incremental Capacity Commissioned		24	30
of which: - Hydro		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		24	30
Incremental Capacity Decommissioned		3	0
of which: - Hydro		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		3	0
Independent Power Producer Capacity[4]	**0**	**0**	**0**
Firm External Purchases	43	43	53
Total Capacity Available to Major Utility	148	169	209

Notes: Numbers in this table have been rounded.
1 Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2 Includes interprovincial transactions, both firm and interruptible.
3 Includes fuel oils.
4 Represents installed net dependable capacity.

Under the Board's load projections, it is expected that NSPI will bring the Trenton units back into service beginning in 2000, followed by 150 megawatts of new oil-fired combustion turbine capacity between 2002 and 2009. In addition, a total of 50 megawatts of hydro and biomass generating capacity was assumed to be purchased from IPPs by 1995.

Beyond 2010, the fuel choices for additional base-load generating capacity in Nova Scotia appear to be coal, oil and, possibly, offshore natural gas.

NSPI's annual SO_2 emissions limit is 160 kilotonnes up to and including 1994. After 1994, this limit is reduced to 145 kilotonnes. In order to control SO_2 emissions, the utility has implemented several environmental protection initiatives. These include directing high-sulphur coal to the new Point Aconi unit which is highly efficient in removing sulphur from coal; using lower-sulphur coal at other plants; and introducing the use of lower-sulphur fuel oil at Tufts Cove. These initiatives will have an overall effect of reducing the utility's SO_2 emissions to well within the post-1994 cap.

5.5.4 New Brunswick

Electrical energy demand in New Brunswick is projected to grow, on average, by 1.5 percent per annum from 13 699 gigawatt hours in 1991 to 18 325 gigawatt hours in 2010.

Major utility firm loads in New Brunswick in 1991 were 13 218 gigawatt hours and 2 591 megawatts. The Board estimates that these will increase at an average rate of 1.6 percent per annum to 17 833 gigawatt hours and 3 472 megawatts by 2010. This is 4.6 percent less than NB Power's 1992 forecast for 2010 of 18 685 gigawatt hours and 3 641 megawatts.

Since 1991, NB Power has installed 100 megawatts of oil-fired combustion turbine capacity at Sainte Rose and the first 443 megawatt unit at the Belledune coal-fired steam generating station, which is equipped with a scrubber to reduce SO_2 emissions. According to the utility, approximately 390 megawatts of coal- and oil-fired generating capacity will be retired over the study period.

Dalhousie units 1 and 2 are scheduled to be converted from coal and heavy fuel oil to Orimulsion in 1994. This fuel is comprised of heavy Orinoco crude from Venezuela mixed with an emulsifying agent. It was also assumed that NB Power will receive regulatory approval to implement a spacer location and relocation process at the Point Lepreau nuclear unit in 1995 in order to extend the life of the unit's pressure tubes by at least ten years.

It is expected that, by 1997, the utility will purchase a total of 55 megawatts from IPPs. This capacity will come from several biomass projects and a small hydro project. Two of the 100 megawatt oil-fired combustion turbines at Millbank, that were installed originally to supply power to Québec, will be returned for use in New Brunswick, one in 1998 and the second in 2002. It is estimated that a further 300 megawatts of oil-fired combustion turbine capacity will be required for peaking purposes between 1999 and 2005.

The Board projects that, by 2006, the NB Power system will need additional base-load generation. As the sites are already developed, the practical choice will be between a second unit at the Belledune plant and an additional nuclear unit at Point Lepreau. The Board assumed that the second 443 megawatt coal-fired steam unit at Belledune would be installed at that time. No additional capacity is required in the province for the remainder of the study period.

If the utility's forecast prevails, one additional 100 megawatt peaking unit would be required in 2004.

Under the Board's load projections, NB Power should be able to stay well within the utility's SO_2 cap of 123 kilotonnes per annum under the projected load conditions.

5.5.5 Québec

The Board estimates that total provincial domestic electrical energy demand in Québec will increase from 161 530 gigawatt hours in 1991 to 237 247 gigawatt hours in 2010, an increase of just over 2 percent per annum on average.

Firm Hydro-Québec loads are projected by the Board to increase at an average annual rate of 2.3 percent from 139 961 gigawatt hours and 28 112 megawatts in 1991 to 216 772 gigawatt hours and 40 677 megawatts in 2010. Hydro-Québec's forecast for 2010 is 202 000 gigawatt hours and 37 690 megawatts.

In 1991, the total dependable capacity available to Hydro-Québec was 32 808 megawatts, plus 600 megawatts of reserve pooling (sharing) with New York. New capacity commissioned or committed between 1991 and 1996 comprises 3 053 megawatts of hydro at various locations and 392 megawatts of natural gas-fired combustion turbines at Bécancour. Between 1997 and 2010, it is expected that the utility will purchase approximately 760 megawatts of power from IPPs. According to the utility, there will be no unit retirements in Québec during the study period.

It is estimated that Hydro-Québec will need additional firm generating capability to meet projected

TABLE 5-5
Supply and Demand of Electricity in Nova Scotia

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	9 776	11 550	12 882
of which - Major Utility Demand	9 398	11 187	12 519
- Other Demand	378	363	363
External Sales[2]	**62**	**0**	**0**
Total Demand	**9 838**	**11 550**	**12 882**
Major Utility Generation	**9 016**	**10 497**	**11 829**
of which: - Hydro[3]	1 030	1 045	1 045
- Coal	6 002	8 531	9 348
- Nuclear	0	0	0
- Other[4]	1 984	921	1 436
Industrial and Minor Utility Generation	**378**	**363**	**363**
Independent Power Production	**0**	**339**	**339**
External Purchases[2]	**444**	**351**	**351**
Total Supply	**9 838**	**11 550**	**12 882**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**1 805**	**2 116**	**2 294**
Firm External Sales	**0**	**0**	**0**
Interruptible loads	**160**	**192**	**242**
System Firm Peak Demand	**1 645**	**1 924**	**2 052**
Major Utility Generating Capacity[5]	**2 119**	**2 264**	**2 434**
of which: - Hydro[3]	385	385	385
- Coal	1 177	1 322	1 342
- Nuclear	0	0	0
- Other[4]	557	557	707
Incremental Capacity Commissioned		185	170
of which: - Hydro[3]		0	0
- Coal		185	20
- Nuclear		0	0
- Other[4]		0	150
Incremental Capacity Decommissioned		40	0
of which: - Hydro[3]		0	0
- Coal		40	0
- Nuclear		0	0
- Other[4]		0	0
Independent Power Producer Capacity[5]	**0**	**50**	**50**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utility	**2 119**	**2 314**	**2 484**

Notes: Numbers in this table have been rounded.
   External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records
2   Includes interprovincial transactions, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes fuel oils.
5   Represents installed net dependable capacity.

TABLE 5-6

Supply and Demand of Electricity in New Brunswick

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**13 699**	**16 654**	**18 325**
of which - Major Utility Demand	13 218	16 162	17 833
- Other Demand	481	492	492
External Sales[2]	**5 633**	**2 819**	**2 968**
Total Demand	**19 332**	**19 473**	**21 293**
Major Utility Generation	**14 999**	**17 330**	**19 232**
of which: - Hydro[3]	2 935	2 614	2 618
- Coal	1 188	3 562	6 326
- Nuclear	5 440	5 037	5 037
- Other[4]	5 436	6 117	5 251
Industrial and Minor Utility Generation	**808**	**792**	**792**
Independent Power Production	**0**	**129**	**129**
External Purchases[5]	**3 525**	**1 222**	**1 140**
Total Supply	**19 332**	**19 473**	**21 293**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**2 695**	**3 265**	**3 552**
Firm External Sales	**560**	**393**	**303**
Interruptible loads	**104**	**104**	**80**
System Firm Peak Demand	**3 151**	**3 554**	**3 775**
Major Utility Generating Capacity[6]	**3 648**	**4 210**	**4 542**
of which: - Hydro[3]	879	879	879
- Coal	303	500	886
- Nuclear	639	639	639
- Other[4]	1 827	2 192	2 138
Incremental Capacity Commissioned		943	643
of which: - Hydro[3]		0	0
- Coal		443	443
- Nuclear		0	0
- Other[4]		500	200
Incremental Capacity Decommissioned		381	311
of which: - Hydro[3]		0	0
- Coal		246	57
- Nuclear		0	0
- Other[4]		135	254
Independent Power Producer Capacity[6]	**0**	**56**	**56**
Firm External Purchases	**105**	**0**	**0**
Total Capacity Available to Major Utility	**3 753**	**4 266**	**4 598**

Notes: Numbers in this table have been rounded.
    External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial sales and exports, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes fuel oils, petroleum coke and orimulsion.
5   Includes interprovincial purchases and imports, both firm and interruptible.
6   Represents installed net dependable capacity.

system energy loads, starting in 1998/99. At that time, the choice will be between developing more hydroelectric projects and installing gas-fired combined cycle units.

In the Current Tech case, the Board assumed that load growth beyond 1997 would be met exclusively by the construction of new hydroelectric projects. A total of 9 275 megawatts of new hydro is required between 1999 and 2009.

In the High Tech case, in which the price of natural gas is lower, it was assumed that two 966 megawatt gas-fired combined cycle blocks would be installed, starting in 1998 and 2006, respectively. In this case, the total new hydro capacity required between 2001 and 2009 would be 5 840 megawatts. Even with lower gas prices, the levelized cost of base-load power from gas-fired combined cycle units in Québec is projected to be higher than that from new hydro projects. However, combined cycle units are less capital-intensive and have considerably shorter lead times. Therefore, in the High Tech case, a mixture of new hydro and gas-fired combined cycle projects might offer greater flexibility in meeting growth in electricity loads in the province.

Under the utility's (lower) load forecast conditions, approximately 3 200 megawatts less generating capacity would be required by the end of the study period.

5.5.6   Ontario

The Board projects that provincial electrical energy demand in Ontario will increase at an average annual rate of 1.8 percent, from 143 460 gigawatt hours in 1991 to 202 389 gigawatt hours in 2010 in the Current Tech case.

Major utility firm loads in Ontario in 1991 were 137 379 gigawatt hours and 22 126 megawatts. By 2010, the Board estimates that loads will have increased to 195 828 gigawatt hours and 30 251 megawatts. This corresponds to an average annual growth rate over the entire period of 1.9 percent. Ontario Hydro's 1993 long-term forecast shows firm loads of 185 270 gigawatt hours and 28 565 megawatts in 2010. That is, the Board's projection is almost 5.7 percent higher by the end of the study period.

Total dependable capacity available to Ontario Hydro in 1991 was 30 207 megawatts. Since then, the fourth 881 megawatt unit at the Darlington A nuclear station was installed. Even with the mothballing of several units, the Ontario Hydro system is currently experiencing surplus generating capacity. It is anticipated that Ontario Hydro will purchase a total of 575 megawatts of IPP capacity between 1992 and 1997, followed by a further 480 megawatts in the next decade.

It is estimated that, in order to satisfy the Board's load projections for Ontario, additional capacity will have to be brought into service starting in 1998. In order to minimize capital expenditures, it was assumed that all base-load requirements between 1998 and 2004 would be met by recommissioning eight mothballed units with a total capacity of 3 200 megawatts at the Lennox, Lakeview and Lambton generating stations. The coal-fired units at Lakeview and Lambton would be fitted with flue gas desulphurization equipment to keep SO_2 emissions below the utility's cap of 175 kilotonnes per annum, which comes into effect in 1994. This additional base-load capacity would be supplemented by 1 680 megawatts of gas-fired combustion turbines for peaking service in the same time period.

In both the Current Tech and High Tech cases, it was assumed that a total of 1 470 megawatts of new hydroelectric capacity would be developed in the second half of the next decade.

For additional major base-load capacity installations starting in the middle of the next decade, the fuel choices are nuclear, coal and natural gas. There is currently a moratorium in Ontario on further nuclear development, and this was assumed to continue. It was assumed that coal-fired units would be installed in the Current Tech case, and gas-fired units in the High Tech case.

In the Current Tech case, three 768 megawatt integrated coal gasification combined cycle (IGCC) blocks burning imported coal would be installed between 2006 and 2010, and would be supplemented by 336 megawatts of gas-fired combustion turbine capacity in 2010. For the High Tech case, the IGCC units would be replaced by three 731 megawatt natural gas-fired combined cycle blocks.

Approximately 1 600 megawatts less new capacity would be required by the end of the study period to meet the lower load projections of Ontario Hydro.

5.5.7   Manitoba

Provincial electrical energy demand in Manitoba was estimated by the Board to increase at an average annual rate of 1.6 percent from 18 019 gigawatt hours in 1991 to 24 590 gigawatt hours in 2010 in the Current Tech case.

According to Statistics Canada, after adjusting for industrial self-generation, electric utility firm loads in Manitoba in 1991 were 17 947 gigawatt hours and 3 463 megawatts. By 2010, the Board expects firm loads to increase to 24 519 gigawatt hours and 4 621 megawatts. Manitoba Hydro forecasts that firm loads in 2010 will

TABLE 5-7
Supply and Demand of Electricity in Québec

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**161 530**	**197 711**	**237 247**
of which - Major Utility Demand	139 961	177 336	216 772
- Other Demand	21 569	20 375	20 475
External Sales[2]	**10 066**	**11 429**	**11 347**
Total Demand	**171 596**	**209 140**	**248 594**
Major Utility Generation	**121 455**	**151 920**	**191 335**
of which: - Hydro[3]	117 040	147 115	186 530
- Coal	0	0	0
- Nuclear	3 910	4 276	4 276
- Other[4]	505	529	529
Industrial and Minor Utility Generation	**21 537**	**20 343**	**20 443**
Independent Power Production	**0**	**4 778**	**4 778**
External Purchases[5]	**28 604**	**32 099**	**32 038**
Total Supply	**171 596**	**209 140**	**248 594**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**30 392**	**36 034**	**43 852**
Firm External Sales	**673**	**362**	**362**
Interruptible loads	**2 280**	**3 500**	**3 175**
System Firm Peak Demand	**28 785**	**32 896**	**41 039**
Major Utility Generating Capacity[6]	**27 030**	**31 987**	**39 750**
of which: - Hydro[3]	25 184	29 749	37 512
- Coal	0	0	0
- Nuclear	685	685	685
- Other[4]	1 161	1 553	1 553
Incremental Capacity Commissioned		4 957	7 763
of which: - Hydro[3]		4 565	7 763
- Coal		0	0
- Nuclear		0	0
- Other[4]		392	0
Incremental Capacity Decommissioned		0	0
of which: - Hydro[3]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[4]		0	0
Independent Power Producer Capacity[6]	**0**	**760**	**760**
Firm External Purchases	**5 778**	**5 628**	**5 528**
Total Capacity Available to Major Utility	**32 808**	**38 375**	**46 038**

Notes: Numbers in this table have been rounded.
     External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial sales and exports, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes fuel oils.
5   Includes interprovincial purchases and imports, both firm and interruptible.
6   Represents installed net dependable capacity.

TABLE 5-8
Supply and Demand of Electricity in Ontario

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**143 460**	**166 545**	**202 389**
of which - Major Utility Demand	137 379	159 984	195 828
- Other Demand	6 081	6 561	6 561
External Sales[2]	**4 921**	**5 520**	**3 254**
Total Demand	**148 381**	**172 065**	**205 643**
Major Utility Generation	**134 894**	**155 411**	**186 763**
of which: - Hydro[3]	33 937	35 774	39 521
- Coal	29 148	25 598	54 296
- Nuclear	70 773	91 785	88 258
- Other[4]	1 036	2 254	4 688
Industrial and Minor Utility Generation	**6 081**	**6 561**	**6 561**
Independent Power Production	**1 466**	**8 023**	**11 387**
External Purchases[5]	**5 940**	**2 070**	**932**
Total Supply	**148 381**	**172 065**	**205 643**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**22 768**	**26 392**	**31 270**
Firm External Sales	**73**	**0**	**0**
Interruptible loads	**642**	**845**	**1 019**
System Firm Peak Demand	**22 199**	**25 547**	**30 251**
Major Utility Generating Capacity[6]	**29 550**	**29 966**	**35 558**
of which: - Hydro[3]	6 677	6 677	8 147
- Coal	8 761	6 631	9 925
- Nuclear	11 521	13 395	12 879
- Other[4]	2 591	3 263	4 607
Incremental Capacity Commissioned		3 315	7 248
of which: - Hydro[3]		0	1 470
- Coal		0	4 434
– Nuclear		2 643	0
- Other[4]		672	1 344
Incremental Capacity Decommissioned		2 899	1 656
of which: - Hydro[3]		0	0
- Coal		2 130	1 140
- Nuclear		769	516
- Other[4]		0	0
Independent Power Producer Capacity[6]	**401**	**1 179**	**1 659**
Firm External Purchases	**256**	**200**	**0**
Total Capacity Available to Major Utility	**30 207**	**31 345**	**37 217**

Notes: Numbers in this table have been rounded.
     External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial sales and exports, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes fuel oils and natural gas.
5   Includes interprovincial purchases and imports, both firm and interruptible.
6   Represents installed net dependable capacity.

be 22 832 gigawatt hours and 4 303 megawatts, or 7 percent less than the Board's projection.

The total installed capacity in Manitoba in 1991 was 4 818 megawatts, of which approximately 92 percent was hydroelectric. Taking into account the installation of units 8 to 10 at the Limestone hydroelectric project in 1992 and the retirement of the coal-fired steam plants at Brandon and Selkirk during the period 1996 and 2006, it is estimated that Manitoba will require additional capacity in 2010 to supply the Board's projected load growth. The choice at that time will be between developing a new hydroelectric project and installing natural gas-fired combined cycle capacity. In the Current Tech case, it was assumed that 170 megawatts of new hydroelectric capacity would be commissioned in 2010. Instead of the new hydro project, a 200 megawatt combined cycle block was assumed to be installed in 2010 in the High Tech case.

If Manitoba Hydro's demand forecast were to materialize, additional generating capacity would not be required in the province until after 2010.

5.5.8   Saskatchewan

Total provincial electrical energy demand in Saskatchewan is projected to increase from 13 847 gigawatt hours in 1991 to 18 623 gigawatt hours by 2010 in the Current Tech case. This is equivalent to an average annual growth rate of 1.6 percent.

The Board estimates that SaskPower's firm loads will grow from 13 297 gigawatt hours and 2 258 megawatts in 1991 to 18 051 gigawatt hours and 2 853 megawatts by 2010. SaskPower's forecast for 2010 is 17 527 gigawatt hours and 2 766 megawatts.

Firm capacity available to SaskPower in 1991 was 2 777 megawatts, including 150 megawatts of emergency reserve from Alberta. In 1992, SaskPower commissioned the first 272 megawatt coal-fired steam unit at the Shand generating station, and retired the 61 megawatt Estevan plant. Beginning in 1995, the emergency reserve from Alberta was assumed to be replaced by 125 megawatts of reserve sharing between the two provinces.

It is expected that by 1995 SaskPower will purchase a total of 43 megawatts of IPP capacity and that a further 50 megawatts will be purchased by 2000. In addition to these purchases, an estimated 150 megawatts of peaking capacity, in the form of gas-fired combustion turbine units, will be installed between 1999 and 2004. In 2006, base-load generation is needed and, in the Current Tech case, it was assumed that a second 272 megawatt coal-fired steam unit would be installed, while

in the High Tech case, a 200 megawatt gas-fired combined cycle block would be commissioned. After that time, no additional capacity is required for the remainder of the study period.

Approximately 50 megawatts of the peaking capacity that are required under the Board's load projections would be eliminated and the commissioning dates of other units delayed by several years under SaskPower's (lower) forecast loads.

5.5.9   Alberta

The Board projects that growth in total provincial electrical energy demand in Alberta will average 2.3 percent per annum during the study period, growing from 44 185 gigawatt hours in 1991 to 68 615 gigawatt hours by 2010 in the Current Tech case.

Major utility firm loads in Alberta in 1991 were 40 676 gigawatt hours and 5 628 megawatts. The Board estimates that utility loads in the province will grow at an average annual rate of 2.3 percent to 59 300 gigawatt hours and 8 290 megawatts in 2007 and to 62 536 gigawatt hours and 8 771 megawatts by the end of the study period in 2010. By contrast, the averages of the working range of forecasts for 2007, published by the Alberta Electric Utilities Planning Council (EUPC) in 1992, are 54 809 gigawatt hours and 7 615 megawatts. This is equivalent to an average annual growth rate of 1.9 percent over 16 years. In 2007, the Board's projection of loads is approximately 8 percent greater than the average of the EUPC's upper and lower forecasts.

Firm capacity available to major utilities in Alberta in 1991 was 7 676 megawatts, including 400 megawatts of reserve sharing with B.C. Since then, two gas-fired combustion turbine units have been added at the Medicine Hat generating station, increasing the capacity of the plant by a total of 34 megawatts. In late 1994, the second 386 megawatt coal-fired steam unit at the Genesee plant will be commissioned. By 1995 an additional 125 megawatts of emergency capacity will become available to Alberta through a reserve sharing arrangement with SaskPower. Another 30 megawatts of steam-fired generation is scheduled to be added at the Medicine Hat station in 1996. The Alberta utilities are expected to purchase a total of 125 megawatts from IPPs by 1995.

According to the EUPC, approximately 2 500 megawatts of mostly coal-fired steam units that were built between the 1950s and the 1970s are due for retirement during the study period. The useful lives of these units could be extended, or alternatively, they could

TABLE 5-9
Supply and Demand of Electricity in Manitoba

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**18 019**	**21 073**	**24 590**
of which - Major Utility Demand	17 947	21 002	24 519
- Other Demand	72	71	71
External Sales[2]	**6 186**	**6 095**	**2 330**
Total Demand	**24 205**	**27 168**	**26 920**
Major Utility Generation	**22 819**	**26 519**	**26 849**
of which: - Hydro[3]	22 554	26 186	26 828
- Coal	243	312	0
- Nuclear	0	0	0
- Other[4]	22	21	21
Industrial and Minor Utility Generation	**72**	**71**	**71**
Independent Power Production	**0**	**0**	**0**
External Purchases[5]	**1 314**	**578**	**0**
Total Supply	**24 205**	**27 168**	**26 920**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**3 463**	**3 964**	**4 621**
Firm External Sales	**700**	**700**	**0**
Interruptible loads	**0**	**0**	**0**
System Firm Peak Demand	**4 163**	**4 664**	**4 621**
Major Utility Generating Capacity[6]	**4 818**	**5 105**	**5 038**
of which: - Hydro[3]	4 434	4 853	5 023
- Coal	369	237	0
- Nuclear	0	0	0
- Other[4]	15	15	15
Incremental Capacity Commissioned		475	170
of which: – Hydro[3]		475	170
– Coal		0	0
– Nuclear		0	0
– Other[4]		0	0
Incremental Capacity Decommissioned		188	237
of which: – Hydro[3]		56	0
– Coal		132	237
– Nuclear		0	0
– Other[4]		0	0
Independent Power Producer Capacity[6]	**0**	**0**	**0**
Firm External Purchases	**0**	**500**	**500**
Total Capacity Available to Major Utility	**4 818**	**5 605**	**5 538**

Notes: Numbers in this table have been rounded.
   External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial sales and exports, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes diesel.
5   Includes interprovincial purchases and imports, both firm and interruptible.
6   Represents installed net dependable capacity.

TABLE 5-10

Supply and Demand of Electricity in Saskatchewan

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**13 847**	**16 659**	**18 623**
of which - Major Utility Demand	13 297	16 165	18 051
- Other Demand	550	494	572
External Sales[2]	**1 140**	**183**	**65**
Total Demand	**14 987**	**16 842**	**18 688**
Major Utility Generation	**13 176**	**15 422**	**17 282**
of which: - Hydro[3]	4 213	3 626	3 626
- Coal	8 678	11 131	12 933
- Nuclear	0	0	0
- Other[4]	285	665	723
Industrial and Minor Utility Generation	**422**	**494**	**572**
Independent Power Production	**0**	**638**	**638**
External Purchases[5]	**1 389**	**288**	**196**
Total Supply	**14 987**	**16 842**	**18 688**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**2 258**	**2 739**	**3 006**
Firm External Sales	**0**	**0**	**0**
Interruptible loads	**0**	**153**	**153**
System Firm Peak Demand	**2 258**	**2 586**	**2 853**
Major Utility Generating Capacity[6]	**2 627**	**2 889**	**3 261**
of which: - Hydro[3]	847	847	847
- Coal	1 424	1 635	1 907
- Nuclear	0	0	0
- Other[4]	356	407	507
Incremental Capacity Commissioned		323	372
of which: - Hydro[3]		0	0
- Coal		272	272
- Nuclear		0	0
- Other[4]		51	100
Incremental Capacity Decommissioned		61	0
of which: - Hydro[3]		0	0
- Coal		61	0
- Nuclear		0	0
- Other[4]		0	0
Independent Power Producer Capacity[6]	**0**	**93**	**93**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utility	**2 627**	**2 982**	**3 354**

Notes: Numbers in this table have been rounded.

     External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.

1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.

2   Includes interprovincial sales and exports, both firm and interruptible.

3   Includes conventional and small hydro.

4   Includes natural gas.

5   Includes interprovincial purchases and imports, both firm and interruptible.

6   Represents installed net dependable capacity.

be replaced by new units, either at the same sites, or at new sites. For the purposes of this study, it was assumed that the old units would be retired and replaced by new units.

If the Board's load projection prevails, Alberta will need additional base-load capacity beginning in 2000. One option available is to develop a 250 megawatt atmospheric fluidized bed combustion unit burning waste petroleum coke in the Fort McMurray area. In the Board's generation expansion plans, this unit was assumed to be installed in 2001 in the Current Tech case and in 2000 in the High Tech case.

The choice in Alberta in the next decade will be between building coal-fired steam units and natural gas-fired combined cycle blocks. In the Current Tech case, it was assumed that ten 370 megawatt base-load coal-fired steam units, supplemented by six 100 megawatt gas-fired combustion turbines for peaking service would be installed between 2000 and 2010. About seven of the new steam units in the Board's expansion plan are required to replace base-load units scheduled for retirement.

In the High Tech Case, in which the price of natural gas is lower, the Board's expansion program between 2000 and 2010 comprises six 370 megawatt coal-fired steam units, seven 240 megawatt gas-fired combined cycle blocks and four 100 megawatt gas-fired combustion turbines.

If the EUPC's forecast materializes, then approximately 900 megawatts of generating capacity indicated in the Board's expansion plan to 2007 would not be required.

5.5.10 British Columbia

Total provincial electrical energy demand in British Columbia is projected to increase from 57 711 gigawatt hours in 1991 to 87 192 gigawatt hours in 2010 in the Current Tech case. This corresponds to an average annual growth rate of 2.2 percent.

Major utility firm loads in B.C. are projected by the Board to grow at an average annual rate of 2.8 percent from 43 147 gigawatt hours and 7 251 megawatts in 1991 to 72 282 gigawatt hours and 13 004 megawatts in 2010. BC Hydro's projection of loads in 2010 is 67 309 gigawatt hours and 12 097 megawatts. That is, the Board is projecting loads that are 7 percent higher by the end of the study period.

Dependable capacity available to major utilities in B.C. in 1991 was 9 958 megawatts, including 400 megawatts of reserve sharing with Alberta. Due to uncertainty concerning the availability of interruptible natural gas supply during the winter season, the Burrard generating station was assumed to contribute only 40 megawatts towards the utility's total dependable capacity. The physical capability of the Burrard plant in 1991 was 912 megawatts.

By 1995, BC Hydro is expected to purchase a total of approximately 200 megawatts of IPP capacity. It was assumed for the purposes of this study that a further 570 megawatts would be purchased from Alcan's Kemano Completion hydroelectric project, starting in 1997. This project is currently undergoing an environmental review and its availability is uncertain. If the project does not go ahead, it is probable that the power would be replaced by purchases from other provinces in the short run and by the construction of alternative capacity in B.C. in the longer run.

As discussed in Section 5.4, power benefits occurring at hydroelectric projects on the Columbia River in the U.S. are, under treaty, due to be returned to the Province of British Columbia beginning in 1998. At that time B.C will have to choose between recovering the benefits for domestic use or continuing to sell them in the U.S.[2] If they are resold in the U.S., additional generating resources will have to be acquired in B.C. to meet the growing domestic demand for electricity. The actual amount of capacity and energy available to B.C. will depend on load growth in the U.S. Pacific Northwest and on the new resources developed to serve it. In the Current Tech and High Tech cases, the benefits were assumed to be returned to B.C., and in the Enhanced Cooperation case, which is discussed in detail in Section 5.7, it was assumed that B.C. would continue to sell these benefits in the U.S.

It was assumed that BC Hydro would continue with the Burrard Upgrade Project which is aimed at increasing the long-term annual energy capability of the plant from 5 310 gigawatt hours to 6 450 gigawatt hours by 2001. Over the last thirty years, annual energy production from Burrard has averaged approximately 1 000 gigawatt hours. In light of the ongoing upgrades at Burrard, as well as the Board's relatively high utility load growth projections, it is projected that BC Hydro will increase average annual production levels at the plant to between 3 000 and 4 000 gigawatt hours.

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2   Since the time the Board's analysis was completed, the Province of British Columbia has decided to continue selling these benefits to the U.S.

TABLE 5-11

Supply and Demand of Electricity in Alberta

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**44 185**	**56 140**	**68 615**
of which - Major Utility Demand	40 676	51 210	62 536
- Other Demand	3 509	4 930	6 079
External Sales[2]	**511**	**506**	**2 352**
Total Demand	**44 696**	**56 646**	**70 967**
Major Utility Generation	**40 961**	**50 833**	**64 228**
of which: - Hydro[3]	2 020	1 636	1 636
- Coal	36 389	41 576	59 379
- Nuclear	0	0	0
- Other[4]	2 552	7 621	3 213
Industrial and Minor Utility Generation	**3 509**	**4 930**	**6 079**
Independent Power Production	**11**	**660**	**660**
External Purchases[2]	**215**	**223**	**0**
Total Supply	**44 696**	**56 646**	**70 967**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**6 006**	**7 695**	**9 393**
Firm External Sales	**0**	**0**	**0**
Interruptible loads	**378**	**616**	**622**
System Firm Peak Demand	**5 628**	**7 079**	**8 771**
Major Utility Generating Capacity[5]	**7 273**	**8 019**	**9 994**
of which: - Hydro[3]	796	796	796
- Coal	5 318	6 018	8 095
- Nuclear	0	0	0
- Other[4]	1 159	1 205	1 103
Incremental Capacity Commissioned		820	4 180
of which: - Hydro[3]		0	0
- Coal		756	3 580
- Nuclear		0	0
- Other[4]		64	600
Incremental Capacity Decommissioned		74	2 205
of which: - Hydro[3]		0	0
- Coal		56	1 253
- Nuclear		0	0
- Other[4]		18	952
Independent Power Producer Capacity[5]	**3**	**125**	**125**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utilities	**7 276**	**8 144**	**10 119**

Notes: Numbers in this table have been rounded.

    External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.

1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.

2   Includes interprovincial transactions, both firm and interruptible.

3   Includes conventional and small hydro.

4   Includes diesel, natural gas and petroleum coke.

5   Represents installed net dependable capacity.

BC Hydro has a "Resource Smart" program[3] which includes the installation of additional generating units at existing hydroelectric plants. It was assumed that a total of 966 megawatts of capacity would be installed under this program between 2001 and 2003.

In both the Current Tech and High Tech cases, it was assumed that two 468 megawatt natural gas-fired combined cycle blocks would be commissioned in the period 1999 to 2004. If the downstream Columbia River benefits were resold in the U.S., one additional 468 megawatt combined cycle block would be required in 1997 to meet provincial requirements.

The choice in B.C. in the second half of the next decade will be between installing additional gas-fired combined cycle generation and developing new hydroelectric projects. In the Current Tech case, a total of 1 175 megawatts of capacity was assumed to be installed at new hydroelectric projects between 2005 and 2009. In the High Tech case, in which gas prices are lower, the new hydroelectric capacity was replaced by two more 468 megawatt combined cycle blocks during the same period. If the downstream benefits were not returned, an additional 360 megawatts of hydroelectric capacity in the Current Tech case, and one additional 468 megawatt combined cycle block in the High Tech case, would be required in the latter half of the next decade.

5.5.11 Yukon

Electrical energy demand in the Yukon in 1991 was 461 gigawatt hours. The Board estimates that this will increase to 509 gigawatt hours in 2010. This is equivalent to an average annual rate of 0.5 percent.

Dependable capacity in the Yukon is 128 megawatts and, unless there is an unexpected increase in load in the territory, there will be no need for additional generating capacity throughout the study period.

5.5.12 Northwest Territories

Total electrical energy demand in the Northwest Territories is projected to grow at an average annual rate of 1.5 percent, from 571 gigawatt hours in 1991 to 755 gigawatt hours by 2010.

The Board projects that electric utility loads in the territory will grow from 455 gigawatt hours and 83 megawatts in 1991 to 639 gigawatt hours and 116 megawatts in 2010. This corresponds to an annual average growth rate of 1.8 percent.

Dependable capacity in the territory is currently 165 megawatts, and this will be sufficient to meet projected loads until 2007, at which time additional energy generation will be required. Two options available to supply this generation are the installation of internal combustion units and the development of small hydro projects. For the purposes of this study, two 7 megawatt diesel internal combustion units were assumed to be installed in 2008 and 2009.

5.6   INTERRUPTIBLE AND TOTAL TRADE

This section describes the interruptible trade that is projected to occur among provinces and between Canada and the U.S. during the study period. It also summarizes the total trade, that comprises both firm trade, that is outlined in Section 5.4, and interruptible trade.

5.6.1   Interruptible Trade

Electricity available to a utility for interruptible trade is that potential generation from existing facilities that remains after all its firm obligations, including domestic demand and firm international and interprovincial commitments, have been met. Generation surpluses are an inherent characteristic of power system operation. For example, hydroelectric output that is surplus to firm requirements is available at times of greater-than-dependable hydrological conditions. Also, thermal projects frequently have surplus energy available, particularly during off-peak periods. The quantities of surplus generation vary with the hourly, daily, seasonal and annual variations in supply and demand for electricity.

Interruptible trade between two systems can be mutually beneficial when the short-run marginal cost of production (principally fuel cost) in one system differs from that in the other system. The low-cost producer benefits by selling, at a profit, energy that is surplus to its own firm needs, while the buyer benefits by being able to purchase energy at a price lower than its own short-run cost of production. Interruptible transfers can also occur with the objective of reducing the overall environmental impacts of electricity production, particularly in reducing gaseous emissions.

The Board's projections of annual international and interprovincial interruptible energy trade take into account the availability of surplus energy, the estimated differences in potential supplier and purchaser incremental fuel costs in all provinces and neighbouring

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3   "Resource Smart" is a program initiated by BC Hydro to capture potential efficiency gains through design and operational modifications to existing electrical facilities.

TABLE 5-12

Supply and Demand of Electricity in British Columbia

	1991[1]	2000	2010
Provincial Energy Summary (GW.h)			
Domestic Energy Demand	**57 711**	**71 509**	**87 192**
of which - Major Utility Demand	43 147	56 599	72 282
- Other Demand	14 564	14 910	14 910
External Sales[2]	**7 272**	**3 250**	**4 097**
Total Demand	**64 983**	**74 759**	**91 289**
Major Utility Generation	**48 633**	**52 337**	**64 951**
of which: - Hydro[3]	47 880	47 103	56 273
- Coal	0	0	0
- Nuclear	0	0	0
- Other[4]	753	5 234	8 678
Industrial and Minor Utility Generation	**14 741**	**15 310**	**15 310**
Independent Power Production	**0**	**4 232**	**4 232**
External Purchases[5]	**1 609**	**2 880**	**6 796**
Total Supply	**64 983**	**74 759**	**91 289**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**7 426**	**10 231**	**13 179**
Firm External Sales	**109**	**174**	**124**
Interruptible loads	**175**	**175**	**175**
System Firm Peak Demand	**7 360**	**10 230**	**13 128**
Major Utility Generating Capacity[6]	**9 558**	**10 037**	**12 716**
of which: - Hydro[3]	9 297	9 308	11 519
- Coal	0	0	0
- Nuclear	0	0	0
- Other[4]	261	729	1 197
Incremental Capacity Commissioned		479	2 679
of which: - Hydro[3]		11	2 211
- Coal		0	0
- Nuclear		0	0
- Other[4]		468	468
Incremental Capacity Decommissioned		0	0
of which: - Hydro[3]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[4]		0	0
Independent Power Producer Capacity[6]	**0**	**775**	**775**
Firm External Purchases	**0**	**670**	**1 350**
Total Capacity Available to Major Utility	**9 558**	**11 482**	**14 841**

Notes: Numbers in this table have been rounded.
External sales and purchases: 1991 includes exchanges, whereas 2000 and 2010 exclude exchanges.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes interprovincial sales and exports, both firm and interruptible.
3   Includes conventional and small hydro.
4   Includes diesel and natural gas.
5   Includes interprovincial purchases and imports, both firm and interruptible.
6   Represents installed net dependable capacity.

TABLE 5-13

Supply and Demand of Electricity in the Yukon

	1991[1]	2000	2010
Territorial Energy Summary (GW.h)			
Domestic Energy Demand	461	407	509
of which - Major Utility Demand	461	407	509
- Other Demand	0	0	0
External Sales	**0**	**0**	**0**
Total Demand	**461**	**407**	**509**
Major Utility Generation	**461**	**407**	**509**
of which: - Hydro[2]	405	360	383
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	56	47	126
Industrial and Minor Utility Generation	**0**	**0**	**0**
Independent Power Production	**0**	**0**	**0**
External Purchases	**0**	**0**	**0**
Total Supply	**461**	**407**	**509**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	**88**	**80**	**100**
Firm External Sales	**0**	**0**	**0**
Interruptible loads	**0**	**0**	**0**
System Firm Peak Demand	**88**	**80**	**100**
Major Utility Generating Capacity[4]	**128**	**128**	**128**
of which: - Hydro[2]	75	75	75
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	53	53	53
Incremental Capacity Commissioned		0	0
of which: - Hydro[2]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		0	0
Incremental Capacity Decommissioned		0	0
of which: - Hydro[2]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		0	0
Independent Power Producer Capacity[4]	**0**	**0**	**0**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utility	128	128	128

Notes: Numbers in this table have been rounded.
1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2   Includes conventional and small hydro.
3   Includes diesel.
4   Represents installed net dependable capacity.

TABLE 5-14

Supply and Demand of Electricity in the Northwest Territories

	1991[1]	2000	2010
Territorial Energy Summary (GW.h)			
Domestic Energy Demand	571	655	755
of which - Major Utility Demand	455	539	639
- Other Demand	116	116	116
External Sales	**0**	**0**	**0**
Total Demand	**571**	**655**	**755**
Major Utility Generation	**455**	**539**	**639**
of which: - Hydro[2]	218	304	304
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	237	235	335
Industrial and Minor Utility Generation	**116**	**116**	**116**
Independent Power Production	**0**	**0**	**0**
External Purchases	**0**	**0**	**0**
Total Supply	**571**	**655**	**755**
Major Utility Capacity Summary (MW)			
Domestic Peak Demand	83	98	116
Firm External Sales	0	0	0
Interruptible loads	0	0	0
System Firm Peak Demand	83	98	116
Major Utility Generating Capacity[4]	165	165	179
of which: - Hydro[2]	43	43	43
- Coal	0	0	0
- Nuclear	0	0	0
- Other[3]	122	122	136
Incremental Capacity Commissioned		0	14
of which: - Hydro[2]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		0	14
Incremental Capacity Decommissioned		0	0
of which: - Hydro[2]		0	0
- Coal		0	0
- Nuclear		0	0
- Other[3]		0	0
Independent Power Producer Capacity[4]	**0**	**0**	**0**
Firm External Purchases	**0**	**0**	**0**
Total Capacity Available to Major Utility	**165**	**165**	**179**

Notes: Numbers in this table have been rounded.

1   Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.

2   Includes conventional and small hydro.

3   Includes diesel.

4   Represents installed net dependable capacity.

regions of the U.S., transmission interconnection capabilities, and historical trade levels. In general, interruptible sales are directed to the export market because fuel costs in the U.S. tend to be higher than in many provinces.

5.6.1.1 Interruptible Exports

All provinces that are interconnected to electricity markets in the U.S. are projected to export interruptible energy during the study period. In 1991, total interruptible energy sales from Canadian utilities to the U.S. were 11 039 gigawatt hours. By 2010 these sales are estimated to be 11 881 and 9 952 gigawatt hours in the Current Tech and High Tech cases, respectively. The lower interruptible exports in the High Tech case are attributable to the greater use of relatively high-priced natural gas generation in Canada in that case, which results in a general reduction of tradeable generation surpluses.

Interruptible power exports from NB Power in 1991 were 848 gigawatt hours and consisted mainly of heavy fuel oil-fired generation. It was estimated that these exports would shift from heavy fuel oil to coal with the commissioning of the new unit at Belledune and the retirement of several units that use heavy fuel oil. The projected interruptible exports from New Brunswick in 2010 are 743 gigawatt hours.

Exports of interruptible energy from Hydro-Québec in 1991 were 1 379 gigawatt hours. This was below historical levels and is attributable to lower-than-average hydrological conditions in that year. Interruptible exports are projected to reach a high of 7 325 gigawatt hours by the mid-1990s, due primarily to energy surpluses from hydroelectric projects commissioned prior to that time. Interruptible exports stabilize after the mid-1990s. By 2010, they are projected to be 3 452 gigawatt hours in the Current Tech case and 3 155 gigawatt hours in the High Tech case. Lower export values in the High Tech case are attributable to reduced levels of hydro surpluses which result from the greater use of gas-fired generation.

Ontario Hydro is projected to become a relatively large exporter of interruptible energy once the availability of the province's nuclear facilities return to near-historic levels. Ontario Hydro's interruptible exports in 1991 were 2 069 gigawatt hours, consisting mainly of coal-fired generation. In the period to 2000, in both the Current Tech and High Tech cases, interruptible exports are supplied mainly by nuclear generation. After 2000, Ontario Hydro's surplus nuclear energy will be gradually absorbed by increasing

domestic loads. At that time, coal-fired generation surpluses are projected to increase as mothballed coal-fired units are recommissioned to meet growth in domestic loads. In both the Current Tech and High Tech cases, interruptible exports in 2010 are projected to be approximately 3 250 gigawatt hours, of which some 2 750 gigawatt hours comes from coal-fired generation. The remaining 500 gigawatt hours is served by nuclear production.

Interruptible exports from Manitoba Hydro in 1991 were 2 503 gigawatt hours. During the period 1994 to 2004, interruptible exports are expected to become negligible as available hydro surpluses are directed to maintaining firm exports to the U.S. After 2004, when Manitoba Hydro's existing firm export commitments come to an end, surpluses are once again available for export on an interruptible basis. By 2010, it is projected that these exports will be 1 137 gigawatt hours in the Current Tech case. The introduction of gas-fired generating capacity to the system in 2010 in the High Tech case results in lower hydro surpluses, and in this case, interruptible exports are reduced to 305 gigawatt hours in that year.

In 1991, interruptible exports from Saskatchewan were 59 gigawatt hours, and these are expected to remain relatively constant over the study period. By 2010, they are projected to increase to 65 gigawatt hours in the Current Tech case, and to decline to 39 gigawatt hours in the High Tech case. The drop in interruptible exports in the High Tech case is attributable to the greater use of relatively high marginal cost gas-fired generation which reduces tradeable surpluses.

BC Hydro and the Alberta utilities exported 3 996 gigawatt hours of interruptible energy in 1991. In that year, interruptible exports from BC Hydro were primarily from hydroelectric production, with a smaller amount of gas-fired generation. Interruptible exports from Alberta through B.C., which came mainly from coal-fired generation, amounted to about nine percent of the B.C. and Alberta total. As a result of the Board's relatively high load growth projections and the estimated increased use of gas-fired generation in B.C., hydroelectric surpluses will gradually decline over the study period. There will likely be a small market for gas-fired interruptible exports from B.C to the U.S. Pacific Northwest to firm up hydroelectric production during below average hydrological conditions, to cover shortfalls that result from maintenance outages, and to displace oil-fired peaking generation. By 2010 in the Current Tech and High Tech cases, it is projected that interruptible exports from BC Hydro will be

1 800 gigawatt hours, 55 percent of which is hydroelectricity, with the remainder supplied by gas-fired generation. As a result of the assumed addition of coal-fired capacity in Alberta in the Current Tech case, interruptible exports from that province are projected to increase to 1000 gigawatt hours by 2010. The greater use of gas in Alberta in the High Tech case has an overall effect of reducing coal-fired generation surpluses. In this case, coal-fired interruptible exports from Alberta in 2010 are projected to be 300 gigawatt hours.

5.6.1.2 Interruptible Interprovincial Trade

All utilities in Canada participate to some degree in interprovincial trade in interruptible energy. Estimates of historical interprovincial interruptible trade were derived from data published by Statistics Canada.

Total gross interruptible interprovincial trade is projected to remain relatively constant over the study period in both the Current Tech and High Tech cases. In 1991, the interruptible component of total gross interprovincial trade (excluding exchanges) was 2 638 gigawatt hours, and this grew to 5 063 gigawatt hours in 1993. By 2010, this trade is projected to reach 7 216 gigawatt hours in the Current Tech case and 5 431 gigawatt hours in the High Tech case. As with interruptible exports, interprovincial interruptible sales are lower in the High Tech case because of the greater use of relatively high marginal cost gas-fired generation.

5.6.2 Total Trade

Total electricity trade includes trade in both firm and interruptible power, each of which includes international and interprovincial components. A detailed presentation of the results of the Board's electricity trade projections are contained in Appendix Tables A5-3 to A5-5.

Table 5-15 shows that total gross electricity exports in 1991 were 19.8 terawatt hours. By 1993, total exports had risen to 29.4 terawatt hours. Over the study period to 2010, the Board projects that total exports will gradually decrease from 1993 levels to 20.3 terawatt hours in the Current Tech case and to 18.4 terawatt hours in the High Tech case.

Figure 5-1 presents a historical profile of international electricity trade from 1980 to 1993, as well as projections to 2010 corresponding to the Current Tech case. The international trade projections for the High Tech case, which are not illustrated, are similar to those of the Current Tech case, except that they are generally lower.

As indicated in Figure 5-1, exports of electric power generally increased until 1987. Reductions in export levels in the late 1980s resulted from a number of events including the introduction of emissions caps from fossil-fuelled electricity production and the reduced availability of nuclear units in Ontario, generally low water conditions in Manitoba, Québec and Labrador,

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TABLE 5-15
Gross Electricity Exports by Province
(Terawatt hours)[1]

	1991[2]	Current Tech 2010	High Tech 2010	Enhanced Coop 2010
New Brunswick	3.1	1.4	1.4	1.2
Québec	5.8	9.8	9.5	9.8
Ontario	2.3	3.3	3.2	3.8
Manitoba	3.3	1.6	0.8	1.6
Saskatchewan	0.1	0.1	0.0	0.1
British Columbia[3]	5.3	4.1	3.4	3.4
Canada	**19.8**	**20.3**	**18.4**	**19.9**

Notes: Numbers in this table have been rounded.
1   Excludes exchanges.
2   Source: National Energy Board records.
3   Includes sales from Alberta.

and higher-than-expected domestic demands. Also, during that period, imports rose sharply, primarily to Ontario and Québec. Exports gradually increased in the early 1990s as conditions in Ontario improved and higher water conditions were experienced in the hydro-rich provinces. During the projection period, gross exports are estimated to range from a high of 29.2 terawatt hours in 1994 to a low of 19.5 terawatt hours in the latter part of the next decade.

Figure 5-1 also shows that imports are projected to range from 0.2 to 4.9 terawatt hours. After 2005, over 95 percent of total Canadian electricity imports in the Current Tech and High Tech cases are associated with the assumed return to B.C. of downstream Columbia River benefits, which begin in 1998.

Figure 5-2 illustrates actual total net interprovincial and gross international trade in electricity in 1991, and projections for 2010 corresponding to the Current Tech and High Tech cases. International trade is presented between exporting provinces and the various U.S. portions of the North American Electric Reliability Council (NERC) regions or power pool areas.

Figure 5-2 shows that the general pattern of trade in most regions in 2010 in the Current Tech case remains similar to that in 1991[4]. The apparent increase in transfers from Labrador to Québec in 2010 is due to the fact that 1991 was a below-average production year at the Churchill Falls hydroelectric development. New Brunswick exports decline as the surplus in that province

is used up. Transfers from New Brunswick to Prince Edward Island gradually increase as on-island electricity demand grows. Exports from Québec increase with time as more hydro projects are developed in the province. Net flows from Québec to Ontario are projected to remain at historically low levels. Exports from Ontario appear to increase but, to some extent, this is attributable to the fact that, in 1991, exports were below-average. Hydro transfers from Manitoba decline over time as the province's surplus generation potential is used up. In the Current Tech case, small quantities of Alberta's coal-fired generating surplus flow to Saskatchewan to displace higher-priced gas-fired generation. Transfers from Alberta to B.C. rise as Alberta's low-cost coal-fired generation surplus increases. Hydro-based exports from B.C. decline but coal-fired exports flowing from Alberta through B.C. increase. However, the assumed return of B.C.'s entitlement to Columbia River downstream benefits results in B.C. becoming a net importer of electricity by the end of the century.

In the High Tech case in 2010, interprovincial and international transfers from Québec, Manitoba and B.C. are slightly less by the end of the study period compared with the Current Tech case because of the displacement

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4 The comparison of actual trade in 1991 and projected trade in 2010 from the hydro-rich provinces is sometimes misleading due to the fact that average hydroelectric production conditions were assumed in the projection period, whereas actual hydroelectric production conditions experienced in 1991 were, in general, below average.

FIGURE 5-1

Historical and Projected Annual Exports and Imports of Electricity – Current Technology Case

Notes: All Trade excludes exchanges
1 Source: National Energy Board records.
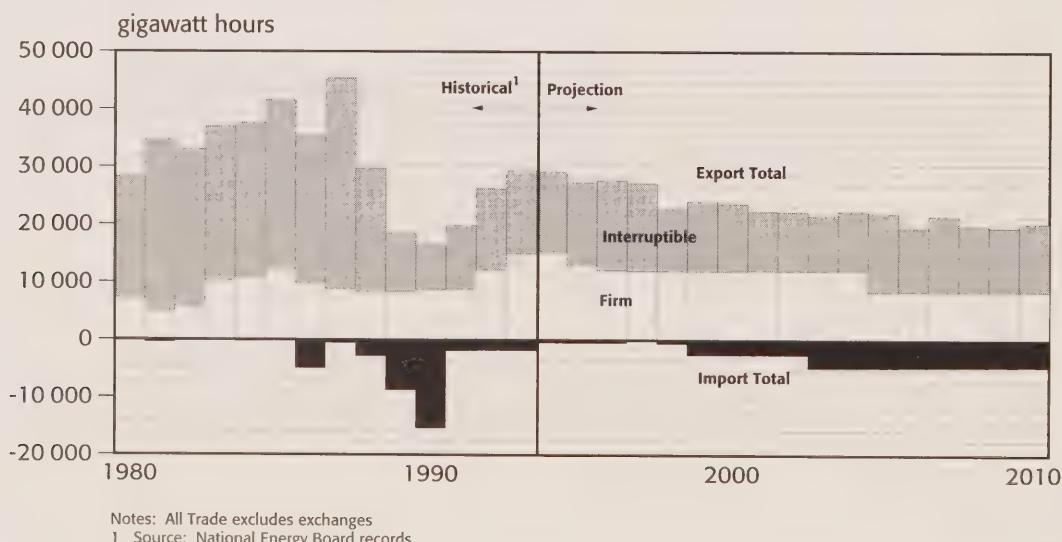
FIGURE 5-2

FIGURE 5-2
Net Interprovincial and Gross International Electricity Trade –
Current Technology and High Technology Cases
(Gigawatt hours)
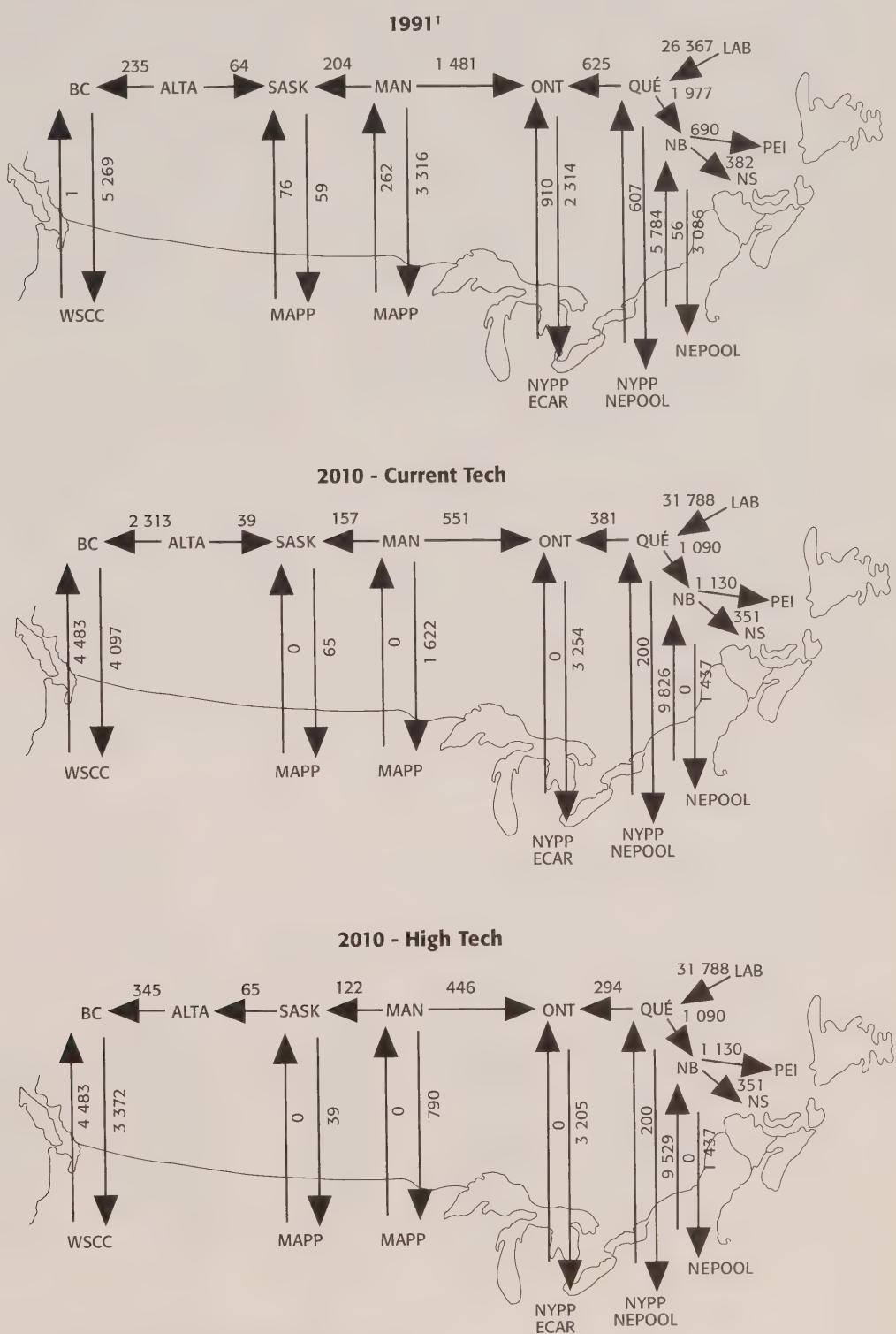
1991[1]

2010 - Current Tech

2010 - High Tech

Notes: All trade excludes exchanges.
1 Source: Statistics Canada Cat. 57-202 for 1991 and National Energy Board records.

of some new hydro projects with gas-fired combined cycle capacity in these provinces by that time. Lower-priced surplus lignite coal-fired generation in Saskatchewan flows to Alberta to displace gas-fired generation. The only other significant change in the High Tech case is that transfers from Alberta to B.C. by 2010 are much-reduced because, in this case, a large portion of new coal-fired base-load capacity in Alberta is displaced by gas-fired combined cycle blocks. This, in turn, reduces that portion of B.C. exports that depends on purchases of coal-fired generation from Alberta.

The firm and interruptible components that made up total gross electricity exports from Canada in 1991 and, for both the Current Tech and High Tech cases, in 2010 are presented in Figure 5-3. In 1991, total firm exports were 8 789 gigawatt hours. These increased to 14 950 gigawatt hours in 1993. In 2010, firm exports in both cases are projected to decrease to 8 423 gigawatt hours, of which 6 375 gigawatt hours are firm commitments from Hydro-Québec. Total interruptible exports are projected to remain relatively constant over the study period. In 1991, this component of total exports was 11 039 gigawatt hours. In 2010, total interruptible exports are expected to be 11 881 gigawatt hours in the Current Tech case and 9 952 gigawatt hours in the High Tech case.

The relative fuel shares of total Canadian gross exports in 1991, and in 2010 for the Current Tech and High Tech cases are illustrated in Figure 5-4. Total

exports of hydro generation decrease from 14.3 terawatt hours in 1991 to 13.5 terawatt hours in 2010 in the Current Tech case. In the High Tech case, exports of hydro generation in 2010 are 12.3 terawatt hours, which are less than in the Current Tech case because of the increased use of gas-fired generation in most of the exporting provinces. The gradual downward trend in hydro exports in both cases is attributable mainly to reduced hydro surpluses. Exports of coal-fired generation increase in 2010 in both cases from 2.1 terawatt hours in 1991 to 4.1 terawatt hours in the Current Tech case, and to 3.3 terawatt hours in the High Tech case. Off-peak generation surpluses associated with new coal-fired generating facilities in Alberta and New Brunswick, as well as with the recommissioning of mothballed units in Ontario, supply most of these exports. Decreased exports of coal-fired generation in the High Tech case are attributable to the substitution of relatively lower-priced coal with higher-priced gas-fired generation, which generally reduces trade potential. Total exports of gas-fired generation, most of which originates in B.C., are projected to increase from 0.4 terawatt hours in 1991 to 1.1 terawatt hours in 2010 in both the Current Tech and High Tech cases. The increase in gas-fired electricity exports corresponds to the greater use of gas-fired generation in B.C. Gas-fired exports remain constant between the two cases reflecting the limited demand in the U.S. for B.C. gas-fired generation. It is estimated that by 2010, nuclear generation in

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FIGURE 5-3

Gross Firm and Interruptible Electricity Exports[1]

Notes:
1 Excludes exchanges
2 Source: National Energy Board records
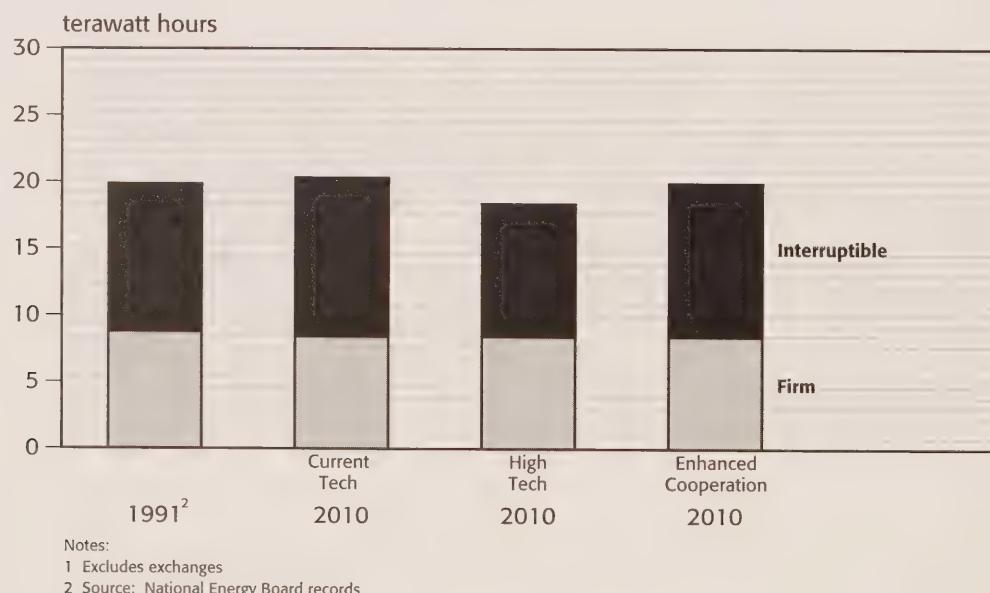
Ontario and New Brunswick will be used almost exclusively to satisfy domestic loads in both the Current Tech and High Tech cases. As indicated in Figure 5-4, nuclear electricity exports decrease in both cases from 2.2 terawatt hours in 1991 to about 0.9 terawatt hours by 2010. Electricity exports from oil and other fuels total approximately 0.7 terawatt hours in the Current Tech and High Tech cases.

5.7   ENHANCED COOPERATION CASE

The primary objective of the Enhanced Cooperation case was to measure the effects of planning and operating generation and transmission systems in Canada on a regional rather than on an individual provincial basis, where there appeared to be economic benefits in doing so. Regional planning would enable the development and use of least-cost electricity supply options to serve markets over wider geographic areas. However, the successful implementation of regional planning would require a greater degree of inter-utility cooperation than exists at present. Also, the use of generating projects to supply regional loads would necessitate increased access to transmission networks.

For the purposes of this analysis, natural gas prices and resulting domestic electricity demand projections in this case were assumed to be the same as in the Current Tech case. Therefore, discussion and comparisons of results corresponding to the Enhanced Cooperation case are made with respect to the Current Tech case. It should not be construed that, because these Current Tech case assumptions were used in the analysis of the Enhanced Cooperation case, the Current Tech case is a more likely scenario than the High Tech case.

Detailed generating capacity and electricity production projections corresponding to the Enhanced Cooperation case analysis are included in Appendix Tables A5-1 and A5-2.

There are potential hydroelectric projects, which have relatively low levelized unit costs, in Labrador on the Lower Churchill River and in Manitoba that are too large in scale to be developed economically to serve local markets. However, if these projects were developed to supply regional load growth, they could reduce the overall cost of electricity supply in certain regions of the country. In the Enhanced Cooperation case, it was assumed that these new large-scale hydroelectric projects would proceed and would be commissioned during the period from 2004 to 2007 at the earliest. The total capacity available from these projects would be in excess of 4 300 megawatts.

Most of the firm interprovincial electricity transactions that were assumed in the Enhanced Cooperation case analysis are associated with the Lower Churchill and additional Manitoba hydroelectric projects and, therefore, begin in the middle of the next decade.

FIGURE 5-4
Gross Electricity Exports by Fuel Type[1]
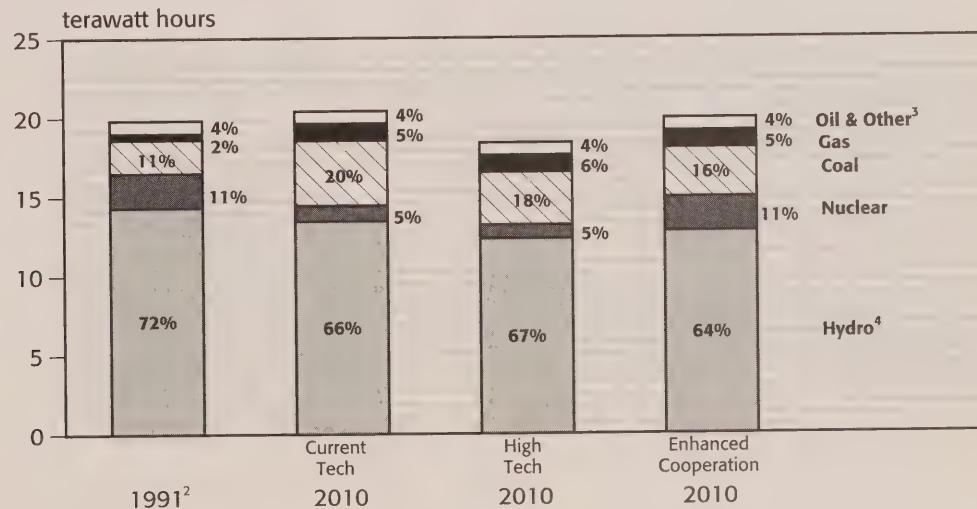
Notes:
1 Excludes exchanges.
2 Source: National Energy Board records.
3 Other includes biomass and orimulsion in New Brunswick.
4 Includes conventional and small hydro.

However, two additional firm interprovincial transactions were assumed in this case, and these would begin in the late 1990s. These include sales from New Brunswick to P.E.I. to displace the first of two combined cycle upgrades at the Charlottetown generating station, and a capacity reserve sharing arrangement between Saskatchewan and Manitoba to eliminate the need for new combustion turbines in Saskatchewan.

Electricity transfers from the Lower Churchill projects to Ontario and the Maritimes were assumed to be wheeled through Québec. Transfers to the Island of Newfoundland would take place by means of a new submarine cable. In the Enhanced Cooperation analysis, the generation expansion plan for Québec remains the same as it is in the Current Tech case.

Firm interprovincial electricity purchases by the utilities in the Maritimes from Lower Churchill projects in Labrador would displace most of the generation additions that are included in the individual provincial generation expansion plans in the Current Tech case after 2004.

New generating capacity that was included in the expansion plan for Ontario after 2005 in the Current Tech case would be displaced by firm electricity purchases from Labrador, as well as by purchases from Manitoba. It was assumed that transmission capacity between Québec and Ontario would be upgraded to deliver electricity from Labrador to Ontario, as well as to capture any potential benefits of hydro/thermal synergies between Québec and Ontario. In addition, it was assumed that Ontario would enter into summer sales transactions with neighbouring U.S. states.

The new 170 megawatt hydroelectric project that is included in the generation expansion plan for Manitoba in 2010 in the Current Tech case was assumed to be displaced by a new larger-scale hydroelectric development in the province in 2006 to serve loads in Ontario, Manitoba and Saskatchewan.

It was assumed that Saskatchewan would purchase firm power from the new hydroelectric project in Manitoba to displace the base-load coal-fired unit scheduled for 2006 in the Current Tech case. A new transmission line would have to be constructed between the two provinces to accommodate the increased power transfers.

It appears that, during the study period, there are few opportunities for cooperation between Alberta and B.C. beyond that which is already taking place. Therefore, no additional cooperation between Alberta and B.C. was assumed in the Enhanced Cooperation case.

In the Enhanced Cooperation case, it was assumed that B.C. would continue to sell its entitlement to downstream Columbia River benefits in the U.S. As a consequence, an additional 468 MW of gas-fired combined cycle capacity in 1997 and 360 MW of hydro capacity in 2009, together with the advancement of other new projects would be required in B.C., compared to the Current Tech case.

In addition to the firm trade described above, surplus energy from the Labrador and Manitoba hydroelectric projects in above-critical hydro production years was assumed to be used to reduce energy production at existing fossil-fuelled plants in the regions served by these projects.

Historical and projected annual exports and imports corresponding to the Enhanced Cooperation case are illustrated in Figure 5-5. The Board's assumption regarding the continued sale by B.C. of downstream Columbia River benefits in the U.S. results in total imports to Canada in this case becoming almost zero. As discussed in Section 5.4, firm exports in the Enhanced Cooperation case were assumed to be the same as in the Current Tech case. In general, exports of interruptible energy and, therefore, total exports are slightly less than in the Current Tech case. As shown in Figure 5-3, by 2010, interruptible exports are projected to be 11.5 terawatt hours compared to 11.9 terawatt hours in the Current Tech case. Correspondingly, total exports, as shown in Table 5-15, are also slightly less than in the Current Tech case. In 2010, total exports are projected to be 19.9 and 20.3 terawatt hours for the Enhanced Cooperation and Current Tech cases, respectively.

Net interprovincial and international electricity flows in 2010 corresponding to the Current Tech and Enhanced Cooperation cases are shown in Figure 5-6. Some flows are substantially different between the two cases. In the Enhanced Cooperation case, most of the generation from the Lower Churchill hydroelectric projects is transferred through Québec to the Maritimes and Ontario, with the remainder being transmitted to the Island of Newfoundland. Flows from Manitoba to Ontario and Saskatchewan in 2010 are greater in the Enhanced Cooperation case than in the Current Tech case because new hydroelectric generating capacity in Manitoba is developed to displace new generating units in Ontario and Saskatchewan. Exports from Ontario in 2010 are slightly greater in the Enhanced Cooperation case because imports of hydropower from Labrador and Manitoba result in more surplus nuclear and coal-fired generation being available in Ontario. Exports from

Manitoba and Saskatchewan in the Enhanced Cooperation case are almost identical to those in the Current Tech case. In the Enhanced Cooperation case, since B.C. was assumed to continue selling its entitlement to downstream Columbia River benefits in the U.S., the province remains a net power exporter. Total gross interprovincial sales in the Enhanced Cooperation case in 2010 are approximately 75 percent greater than those in Current Tech case.

Figure 5-4 presents the relative fuel shares associated with total gross electricity exports in 2010 for the Enhanced Cooperation case, and compares them with those corresponding to the Current Tech case. Exports of hydro generation in the Enhanced Cooperation case are 12.8 terawatt hours, while in the Current Tech case, exports from this source are 13.5 terawatt hours. Hydro generation exports are lower in the Enhanced Cooperation case mainly because of reduced hydro surpluses in B.C. resulting from the assumed resale of downstream Columbia River benefits in the U.S. Exports of coal-fired generation in 2010 are projected to be 3.1 terawatt hours in the Enhanced Cooperation case, compared to 4.1 terawatt hours in the Current Tech case. Lower coal-fired generation exports in the Enhanced Cooperation case are attributable to the substitution of new coal-fired generation in New Brunswick and Ontario with firm hydroelectric purchases from Labrador and Manitoba, which results in reduced coal-fired generation surpluses. The firm hydroelectric purchases also result in additional surpluses of nuclear generation becoming available for export from Ontario, as well as more oil-fired surpluses for export from New Brunswick. In the Enhanced Cooperation case in 2010, exports of nuclear and oil-fired generation are projected to reach 2.2 and 0.7 terawatt hours, respectively. Exports of gas-fired generation remain constant between the two cases at 1.1 terawatt hours. Electricity exports from other fuels are projected to total approximately 0.1 terawatt hours.

5.8 SUMMARY OF SUPPLY AND DEMAND OF ELECTRICITY IN CANADA

The Board's projections of total supply and demand for electrical energy and capacity in Canada in 2010 are summarized in Table 5-16 for the Current Tech, High Tech and Enhanced Cooperation cases. The various fuel types associated with electricity production and generating capacity are also presented in this table, and are illustrated in Figures 5-7 and 5-8, respectively.

Total domestic energy demand in Canada in 1991 was approximately 475 terawatt hours. The Board projects that, by 2010, this will grow to about 687 terawatt hours in the Current Tech case and to 689 terawatt hours in the High Tech case, which corresponds to an average annual growth rate of 2.0 percent in both cases. For the purposes of this study, domestic demand projections in the Enhanced Cooperation case were assumed to be the same as in the Current Tech case.

Total electricity generation in Canada is projected to increase from 493 terawatt hours in 1991 to just over

FIGURE 5-5
Historical and Projected Annual Exports and Imports of Electricity – Enhanced Cooperation Case
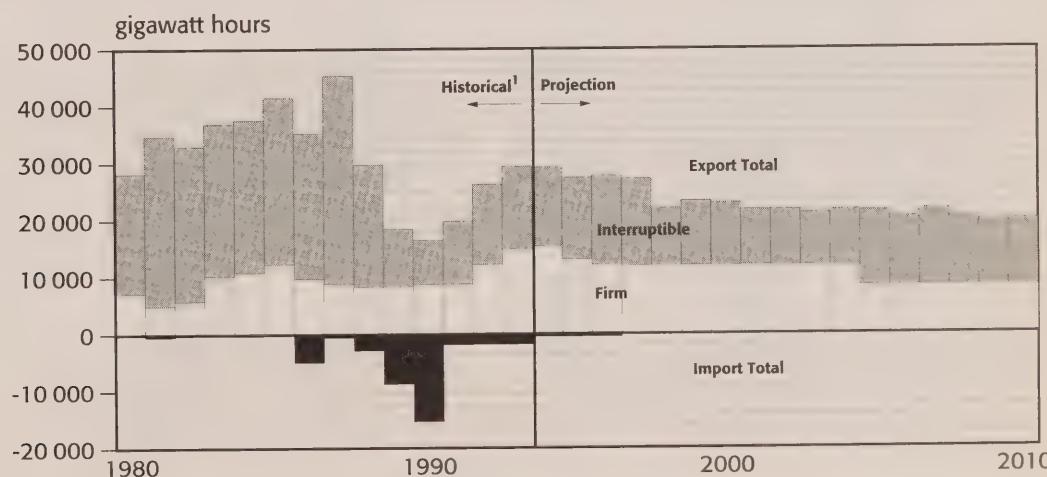
Notes: All Trade excludes exchanges.
1 Source: National Energy Board records.

FIGURE 5-6

Net Interprovincial and Gross International Electricity Trade –
Current Technology and Enhanced Cooperation Cases
(Gigawatt hours)

1991[1]

235 ←— BC ←— ALTA —→ SASK ←— 64 —→ 204 MAN ←— 1 481 —→ ONT ←— 625 —→ QUÉ

26 367 — LAB
1 977
690 — PEI
NB
382 NS

BC: 1 / 5 269 → WSCC
SASK: 76 / 59 → MAPP
MAN: 262 / 3 316 → MAPP
ONT: 910 / 2 314 → NYPP ECAR
QUÉ: 607 / 5 784 → NYPP NEPOOL
NB: 56 / 3 086 → NEPOOL

2010 - Current Tech

2 313 BC ←— ALTA —→ 39 SASK ←— 157 — MAN — 551 —→ ONT ←— 381 — QUÉ

31 788 — LAB
1 090
1 130 — PEI
NB
351 NS

BC: 4 483 / 4 097 → WSCC
SASK: 0 / 65 → MAPP
MAN: 0 / 1 622 → MAPP
ONT: 0 / 3 254 → NYPP ECAR
QUÉ: 200 → NYPP NEPOOL
NB: 9 826 / 0 / 1 437 → NEPOOL

2010 - Enhanced Cooperation

2 313 BC ←— ALTA — 0 — SASK ←— 2 557 — MAN — 5 838 —→ ONT ←— 9 144 — QUÉ

43 787 — LAB   4 195 NFLD
4 349
1 130 — PEI
NB
1 366 NS

BC: 0 / 3 422 → WSCC
SASK: 0 / 52 → MAPP
MAN: 0 / 1 622 → MAPP
ONT: 0 / 3 786 → NYPP ECAR
QUÉ: 200 → NYPP NEPOOL
NB: 9 826 / 0 / 1 209 → NEPOOL

Notes: All trade excludes exchanges.
1 Source: Statistics Canada Cat. 57-202 for 1991 and National Energy Board records.

700 terawatt hours by 2010 in all three cases. The difference between the total electricity generation and domestic demand is the amount of net exports to the U.S. Total energy generation in 2010 in the Enhanced Cooperation case is higher than in the Current Tech case and this is attributable almost entirely to the assumption regarding the return of downstream Columbia River benefits to B.C. In the Enhanced Cooperation case it was assumed that B.C. would continue to sell these benefits in the U.S., resulting in additional electricity production in B.C., whereas in the Current Tech and High Tech cases these benefits were assumed to be returned to B.C.

As highlighted in Figure 5-7, hydroelectric production is projected to remain the dominant source of electricity supply in all three cases, although its relative share is expected to diminish slightly over the study period. This decrease in share is less pronounced in the Enhanced Cooperation case due to the development of large hydroelectric projects towards the end of the study period to serve regional loads. Nuclear and coal-fired generation remain the next largest components. The relative share of coal-fired generation increases slightly from 17 percent in 1991 to a range of between 18 and 20 percent in 2010. The reduced share of coal-fired generation in the High Tech case compared to the Current Tech case is attributable to the greater emphasis on new gas-fired generating capacity in the High Tech case, whereas in the Enhanced Cooperation case, the reduction in coal-fired generation is caused by increased

hydroelectric production. The nuclear generation share is projected to decrease from 16 percent in 1991 to 14 percent by 2010 in all three cases. The relative share of natural gas-fired generation in the High Tech case is projected to increase from 2 percent in 1991 to 10 percent in 2010. This is double the projected natural gas share in 2010 in the Current Tech and Enhanced Cooperation cases. Total shares of oil and other fuels are projected to remain relatively constant over the study period at about 3 to 4 percent in all three cases.

Total non-coincident domestic peak demand, as presented in Table 5-16, is projected to rise from 87 gigawatts in 1991 to approximately 123 gigawatts in all three cases. Average annual growth in total peak demand over the study period is between 1.8 and 1.9 percent. Domestic peak demand increases at a slightly lower rate than does energy demand because of general increases in system load factors.

Table 5-16 shows that the total generating capacity in Canada in 1991 was 102 gigawatts. In order to reliably supply the projected electricity loads during the study period, the Board expects that between 29 and 31 gigawatts of additional generating capacity will have to be added between 1991 and 2010. Expected generating capacity savings in the Enhanced Cooperation case resulting from increased regional planning are offset by increased generating capacity requirements in B.C. necessitated by the assumption regarding the continued sale of downstream Columbia River benefits in the U.S.

FIGURE 5-7

Production of Electricity by Fuel Type
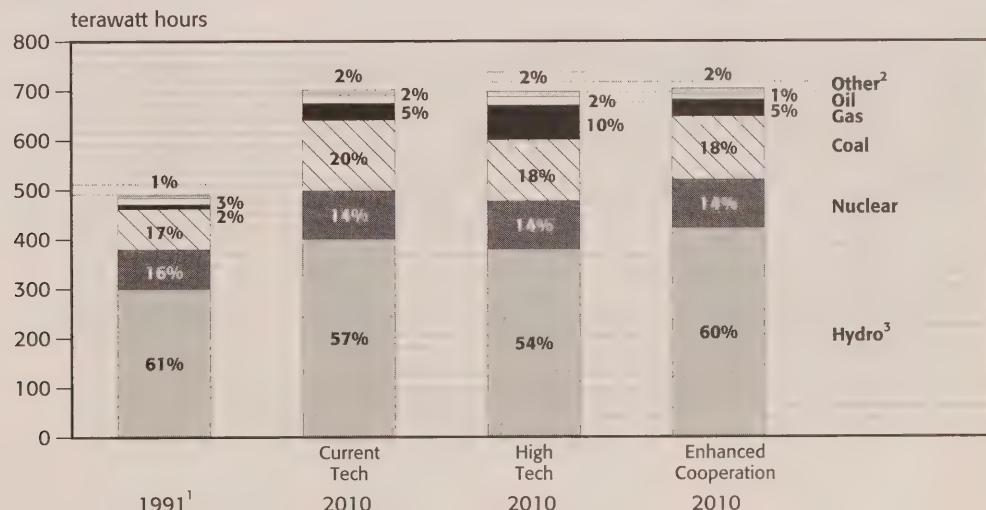
Notes:
1 Source: Statistics Canada Cat. 57-202 for 1991.
2 Other includes alternative and renewable fuels, petroleum coke and orimulsion.
3 Includes conventional and small hydro.

In 1991, hydro generating capacity represented approximately 59 percent of the total generating capacity in Canada. Figure 5-8 shows that, by 2010, the relative share of hydro capacity is estimated to remain at 1991 levels in the Current Tech case, reduce to 56 percent in the High Tech case, and increase to 61 percent in the Enhanced Cooperation case. The reduced hydro share in the High Tech case is attributable to the greater installation of gas-fired generating capacity, whereas the increase in hydro share in the Enhanced Cooperation

TABLE 5-16

Supply and Demand of Electricity in Canada

	1991[1]	Current Tech 2010	High Tech 2010	Enhanced Cooperation 2010
National Energy Summary (TW.h)				
Domestic Energy Demand	475	687	689	687
Exports[2]	25	20	18	20
Total Demand	499	707	708	706
Energy Generation by Fuel Type	493	702	703	706
Of which: – Hydro[3]	305	401	385	423
– Coal	82	142	123	127
– Nuclear	80	98	98	98
– Oil	12	16	16	12
– Natural Gas	10	34	70	36
– Other[4]	4	11	11	11
Imports[2]	6	5	5	0
Total Supply	499	707	708	706
National Capacity Summary (MW)				
Domestic Peak Demand[5]	86 663	122 625	123 118	122 625
Exports[2]	1 311	536	536	536
System Peak Demand	87 974	123 161	123 654	123 161
Generating Capacity by Fuel Type[6]	102 404	133 542	131 647	133 113
Of which: – Hydro[3]	60 772	78 460	73 680	81 465
– Coal	17 352	22 155	18 099	19 136
– Nuclear	12 845	14 203	14 203	14 203
– Oil	7 610	8 383	8 383	8 036
– Natural Gas	2 867	8 356	15 297	8 288
– Other[4]	958	1 985	1 985	1 985
Imports[2]	475	2 275	2 275	925
Total Capacity Available	102 879	135 817	133 922	134 038

Notes: The numbers in this table have been rounded.
1 Source: Statistics Canada Cat. 57-202 for 1991 for energy, Cat. 57-206 for 1991 and consultations with utilities for capacity, and National Energy Board records.
2 Includes firm and interruptible. 1991 includes exchanges whereas 2010 excludes exchanges.
3 Includes conventional and small hydro.
4 Includes alternative and renewable fuels, petroleum coke and orimulsion.
5 These numbers are the sum of provincial peak demands, which are not necessarily coincident peaks.
6 Represents installed net dependable capacity.

case results from the increased installation of hydro to displace mostly coal-fired generating capacity. The overall share of coal-fired generating capacity in 2010 remains at 1991 levels in the Current Tech case, but reduces in the High Tech and Enhanced Cooperation cases. Coal-fired capacity share in 2010 in the Current Tech case is 17 percent. Substitution of coal-fired capacity with gas-fired capacity in the High Tech case and with hydro in the Enhanced Cooperation case reduces the coal-fired capacity share by 2010 in these two cases to 14 percent. The share of gas-fired generating capacity increases from 3 percent in 1991 to 12 percent in 2010 in the High Tech case. The relative share of gas-fired capacity in 2010 in both the Current Tech and Enhanced Cooperation cases are projected to increase to 6 percent. The share of nuclear capacity is projected to reduce from 13 percent in 1991 to 11 percent in 2010 for all three cases studied. The share of generating capacity using other fuels, which includes mainly oil, is projected to decrease slightly from a total of 8 percent in 1991 to 7 percent in 2010 in the Current Tech and High Tech cases, but remains unchanged in the Enhanced Cooperation case.

5.9 SUMMARY OF PRIMARY ENERGY DEMAND FOR ELECTRICITY PRODUCTION IN CANADA

The Board's projections of total Canadian primary energy demand for electricity production, expressed in petajoules, in 1991 and 2010 for the Current Tech, High Tech and Enhanced Cooperation cases, are summarized in Table 5-17. A detailed presentation of total primary energy demand by fuel type is contained in Appendix Table A5-6.

Figures contained in Table 5-17 were calculated by applying plant-specific average net heat rates to corresponding estimates of plant electricity generation. Heat rate is a measure of the efficiency of a generating facility, and is usually expressed as the ratio of the number of kilojoules of input energy required to produce a single kilowatt-hour of electrical energy. Average heat rates for existing generating plants were developed using the three most recent consecutive years of historical data available from Statistics Canada.

The pattern of fuel requirements presented in Table 5-17 for a given fuel type generally follows the electricity production values given in Table 5-16.

FIGURE 5-8

Generating Capacity by Fuel Type[1]

Notes:
1 Represents installed net dependable capacity.
2 Source: Statistics Canada Cat. 57-206 for 1991 and consultations with utilities.
3 Other includes alternative and renewable fuels, petroleum coke and orimulsion.
4 Includes conventional and small hydro.
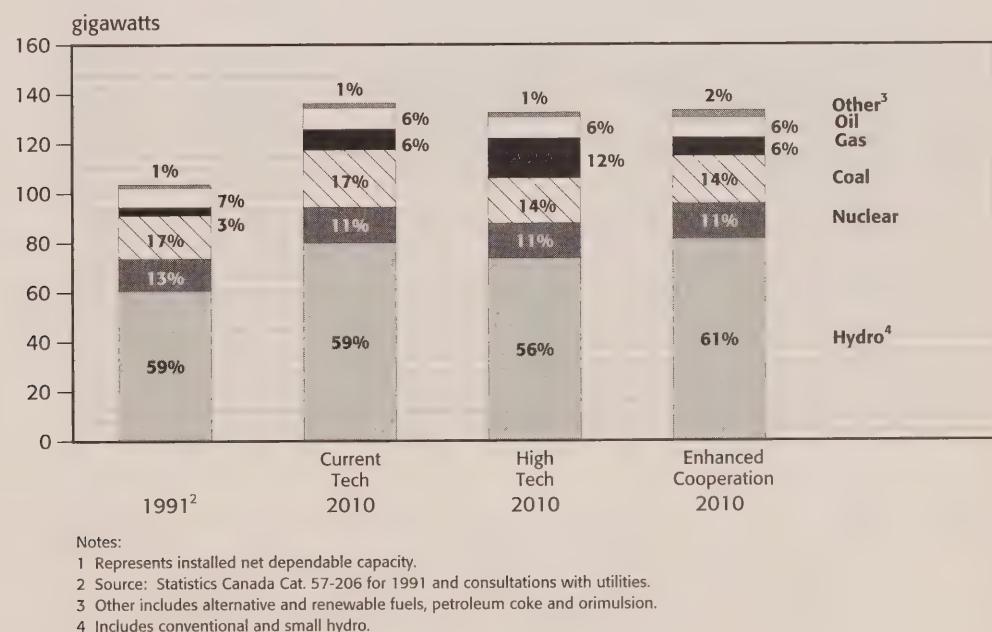
However, the combined average heat rates in predominately thermal systems may change over time as newer, more efficient, generating units are commissioned and older, less efficient, units are retired.

Total primary energy demand for electricity production in Canada in 1991 was 3 220 petajoules. By 2010, this demand is projected to increase to 4 688 petajoules in the Current Tech case, 4 739 petajoules in the High Tech case, and 4 583 petajoules in the Enhanced Cooperation case. In general, by 2010 primary fuel demands for all fuels increase over corresponding 1991 levels. Total primary energy demand in 2010 is just over 50 petajoules higher in the High Tech case compared to the Current Tech case. In some provinces, more-efficient gas-fired generation is substituted for less-efficient coal-fired generation in the High Tech case, resulting in less primary energy demand in these provinces. However, this is more than offset by the substitution of less-efficient gas-fired electricity production for more-efficient hydro generation in other provinces. The

contribution of hydro generation to primary energy demand in 2010 is 1 385 petajoules in the High Tech case compared to 1 443 petajoules in the Current Tech case. Requirements for coal in 2010 are also less in the High Tech case (1 331 petajoules) compared to the Current Tech case (1 518 petajoules). On the other hand, the contribution of natural gas-fired generation to primary energy demand in 2010 is significantly greater in the High Tech case (537 petajoules) compared to 245 petajoules in the Current Tech case. Primary energy demands for other fuels in 2010 are approximately the same in these two cases.

In 2010, total primary energy demand for electricity generation in the Enhanced Cooperation case is 105 petajoules less than in the Current Tech case, despite the fact that total energy generation in the Enhanced Cooperation is almost 4 terawatt hours higher. This is attributable to the greater use of hydro generation and reduced amounts of coal- and oil-fired steam generation in the Enhanced Cooperation case. The

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TABLE 5-17

Primary Energy Demand for Electricity Generation – Canada

(Petajoules)[1]

		1991[2]	Current Tech 2010	High Tech 2010	Enhanced Cooperation 2010
Hydro[3]		1 099.7	1 443.2	1 385.4	1 522.6
Uranium		969.5	1 213.2	1 213.2	1 213.2
Coal		913.3	1 518.1	1 331.0	1 365.4
of which:	- Bituminous	151.7	300.8	245.6	201.3
	- Subbituminous	411.7	630.0	508.6	630.0
	- Lignite	127.8	172.9	163.7	151.3
	- Imported	222.1	414.4	413.2	382.9
Natural Gas		76.3	244.9	537.2	256.3
Oil		130.4	172.0	175.0	128.7
of which:	- Heavy Fuel Oil	118.3	150.7	153.7	112.9
	- Light Fuel Oil	1.4	1.6	1.7	1.2
	- Diesel	10.7	19.6	19.7	14.6
Alternatives & Renewables		30.1	51.9	51.9	51.9
Other[4]		1.1	45.0	45.0	45.0
Total Primary Energy Equivalent		3 220.5	4 688.3	4 738.7	4 583.1

Notes: The numbers in this table have been rounded.
1   Input energy converted from gigawatt hours using a conversion of 0.0036 PJ/GW.h for hydro and plant – specific average net heat rates for all thermal plants.
2   Source: Statistics Canada Cat. 57-202 for 1991.
3   Includes conventional and small hydro.
4   Includes petroleum coke and orimulsion.

contribution of hydro generation to primary energy demand in 2010 in the Enhanced Cooperation case is 1 523 petajoules compared to 1 443 petajoules in the Current Tech case. Corresponding contributions of coal are 1 365 and 1 518 petajoules, respectively, and for oil are 129 and 172 petajoules, respectively. Demand for natural gas in 2010 in the Enhanced Cooperation case is 256 petajoules compared to 245 petajoules in the Current Tech case mainly because of the assumption regarding the continued sale of downstream Columbia River benefits in the U.S. and the resulting increases in gas-fired electricity production in B.C. The contributions of other fuels are approximately the same in these two cases.

NATURAL GAS

6.1   APPROACH

The key element of the natural gas analysis examines the implications for the future outlook of supply costs. In one case we examine the traditional approach that supply costs will continue to rise as resources become increasingly more costly to exploit. In the second case it is assumed that technology and geological knowledge will prevent supply costs from rising appreciably.

There are six main components in the Board's analysis of natural gas supply and demand. First, there is the review and assessment of the estimates of the magnitude and character of the North American resource base. Second, the associated costs of finding and developing additional gas to market are assessed. Third, the rationale for the major analytical assumptions, such as: the rate of technological enhancements, the parameters governing fuel switching and the structure and cost of the distribution network, is developed. Fourth, the natural gas demand is projected using the NEB's projection for Canada and GRI's projection for the United States. Fifth, the analysis of the gas flows and prices based on the quantity of gas available, its supply costs and the anticipated gas demand is undertaken. For this analysis the NEB uses, as it has in the past two editions of this report, the North American Regional Gas (NARG) model developed by Decision Focus Inc. The detailed description of NARG can be found in Appendices 6.1 to 6.2. Sixth, the deliverability from Canadian sources is evaluated. A significant part of future deliverability is expected to come from reserves additions, and the drilling required to make the supply available is an important part of the analysis. The final part of the analysis concerns the Export Impact Assessment which is one component of the Board's regulatory procedure to assess the effect of long-term gas exports.

The specific approaches taken with the resource evaluation, the supply costs and deliverability are more fully described at the start of each respective section.

The approach to developing estimates of natural gas resources is more rigorous and includes significantly more in-house evaluation of Canadian and U.S. resources than had been undertaken in previous reports. In addition there has been more consultation with various agencies and companies in both Canada and the United States concerning the resource base.

For the supply cost calculations a different approach has been used than in previous reports. In this analysis, the supply costs are now directly based on the geological evaluation of the various supply regions. Supply costs have been developed on the same basis for both Canada and the major producing regions of the U.S.

The NEB's energy demand model (EDM) was used for the projection of demand for Canadian gas. The demand/price determination process is iterative between the EDM and NARG to ensure consistency between the two models. The natural gas demand projections for the U.S. were derived from the Gas Research Institute 1993 Base Line Forecast.

The NARG model gives an equilibrium solution for gas supply, demand and price for North America. The characteristics of the model are such that it gives linear transitions in the solution of prices and volumes from period to period, which may not always be reflective of actual market conditions. There are a number of limitations to the model. For example, burner tip prices are directly determined from supply costs, pipeline toll discounting is not possible and oil prices are exogenous and do not vary with demand created by fuel switching.

Some changes have been made by the Board to the NARG framework of supply basins, demand regions and pipeline system. These are: a Mexican demand node has been added; the California Energy Commission's pipeline tolling methodology have been adopted; and switchable gas-to-oil demand for Canada was restricted to 25 percent of the non-core industrial market sector. Additionally, the backstop price has been reduced to US(1991)$5.00 per Mcf from US(1987)$6.00 per Mcf in the 1991 analysis.

To address the main issue of technology and its impact on natural gas markets, we have developed two cases, based on alternative views of how advances in geological knowledge and technological progress might affect the shape of the supply cost curves. The two cases are "Current Technology" and "High Technology". The Current Technology case assumes that no new technologies will be introduced, but existing technologies will evolve, resulting in some improvement through time, i.e., the rate of increase in supply cost is moderated. The High Technology case assumes a flatter supply cost curve, i.e., the rate of increase is very slow and in some cases zero. This is consistent with the

observation that many commodities exhibit a flat or declining supply cost throughout their period of exploitation. A flatter supply curve could result from the development and adoption of new technologies which apply to conventional resources, or lead to the development of the unconventional resource base. The Board does not assume that either of these cases as "most likely" and therefore gives them equal weight.

In order to explore some of the other issues related to the evolution of gas markets, two sensitivity cases have been examined. We have chosen to test the demand side by substantially increasing the requirement for gas in the U.S.: Sensitivity Case 1, High U.S. Electrical Demand, is designed to assess the impact of an additional 3 Tcf per year of natural gas demand in the electrical generation sector. On the supply side, we address uncertainty by assuming that a new source of gas will be introduced to the market in the year 2000: Sensitivity Case 2, Low Cost Gas Supply, assesses the impact of a new, competitively-priced gas source with a resource base of 70 Tcf, perhaps located in Mexico, on the North American market.

These sensitivities also form the basis for framing the analysis of the long-term implications of alternate levels of North American supply and demand on Canadian exports and domestic gas markets and prices. During the consultation process opinions were expressed that the Board should include an "Export Impact Assessment" with the Supply and Demand report, rather than publish a separate document.

The deliverability and drilling projections are developed from in-house models that make projections of future supply using actual and projected reservoir performance of producing pools, the quality and quantity of unconnected reserves and the supply from resource additions. The deliverability projection takes account of projected demand, producer net-backs, well cost and the rate of reserves additions. The amount of drilling required in order to develop existing reserves and to find and exploit resource additions is developed on an annual basis.

6.2   NATURAL GAS RESOURCES

6.2.1   Natural Gas Resource Base

6.2.1.1 Approach

The North American natural gas resource base consists of in-place volumes of conventional and unconventional natural gas. For conventional resources,

a portion has been produced, a portion discovered and a much larger portion still remains to be discovered. For the unconventional resource base, the resource has been identified; however, the marketable portion is difficult to estimate. To date, development and production of unconventional gas has occured only in U.S. basins.

Conventional natural gas can be recovered from the in-place resource base using standard production practices. Recovery efficiencies vary between geological formations, and also depend on depth and various reservoir parameters. The primary focus of this report is on conventional gas resources.

Unconventional natural gas resources exist in formations that require specialized recovery or completion techniques and are often characterized by poor recovery efficiencies. Examples of unconventional natural gas are accumulations in tight reservoirs, methane trapped in coal beds, natural gas deposits in organic rich shale beds and gas hydrates.

The estimation of in-place natural gas resources is not an exact science. Since the volumes of gas resources cannot be measured with any confidence, it is necessary to produce estimates by making use of assessment methods that are based on statistical analysis, geological framework, models and extrapolations from known discoveries.

Estimates for in-place conventional gas resources are available for most Canadian geological basins from the Geological Survey of Canada, which uses statistical methods[1] to assign a probability to its estimates. The Alberta Energy Resources Conservation Board (ERCB), using a different approach, recently released the study, Ultimate Potential and Supply of Natural Gas in Alberta[2], in which estimates for ultimate conventional in-place resources, and ultimate recoverable resources were provided. Methodologies applied by these two agencies are largely dependent upon detailed, accurate, and up-to-date information on gas reserves, which provide the baseline data for statistical extrapolations.

Regardless of the analytical assumptions, the estimates are likely tempered to some degree with assumptions regarding future supply costs, and the level of technology available for exploiting the resource base. Therefore, it is important to take account of the underlying assumptions when individual resource

1   Lee, P.J. 1993. Two decades of Geological Survey of Canada petroleum resource assessments. Can. J. Earth Sci. 30 pp. 321-332

2   Energy Resources Conservation Board, 1992. Ultimate Potential and Supply of Natural Gas in Alberta. ERCB Report 92-A, Calgary, Alberta.

estimates are assessed or compared with other estimates. It serves little purpose to count every molecule of gas that is trapped or is estimated to occur in every geological formation within North America since the supply cost and technology which corresponds to such an estimate are only known for the established reserves component.

Figure 6-1 illustrates marketable gas resource potential estimates, through time, for the Western Canada Sedimentary Basin (WCSB). Estimates have more than doubled over a twenty year period and the total of cumulative production plus remaining established reserves exceeds estimates of potential dating from the mid-1970's. Reasons for such significant increases in resource estimates are better technologies for discovery and recovery of resources, as well as the benefit gained from better quality data, a better understanding of the geology of the basin, change in prices, pool performance, exploration efficiencies and assumptions regarding variations in supply costs.

The current challenge is to provide an estimate of natural gas resources within a framework of assumptions regarding technology and supply costs, that properly reflects the availability of that resource over the projection period. First, the estimator must adopt a set of definitions for the various components of the resource base that adequately describes the uncertainty and quality of the estimate. Then the task is to provide the estimates of marketable natural gas resources, for both discovered and undiscovered conventional components, as well as estimates for marketable unconventional resources. In doing so, the assumptions regarding available technology and to some extent expected supply costs are incorporated.

The relationship between the conventional and unconventional components of the in-place resource base is illustrated graphically by the cumulative resource triangle (Figure 6-2). The breadth of the triangle at any point corresponds to the quantity of resources, and the position relative to its apex is indicative of the quality (pool size, reservoir quality, byproducts), accessibility or supply cost attached to that resource. In effect, the line marked "technology/price uncertainty" defines the portion of the in-place gas resource, from the apex of the triangle to the line, that is estimated, at a given point in time, to be marketable gas. Nature appears to have distributed gas resources in such a way that the volume of high quality resources near the top of the triangle is relatively small, whereas the volumes become increasingly larger as the quality or accessibility of the resource decreases.

To move down the triangle and capture the added resource potential implies increased supply costs, or technological advancement or better exploration efficiencies. Although the vertical axis can be related to increasing prices, it is not restricted to this criteria alone. The effect of improvements to existing technology, or the development of entirely new technologies would have the effect of capturing additional resources into the estimate, similar to the increase resulting from higher prices.

Proceeding further from the apex of the cumulative gas resource triangle, unconventional resources are added into the total. Coalbed methane, tight gas, and eventually organic rich shales, gas hydrates or gas in aquifers become viable to produce. The placement of the individual resource components within the

FIGURE 6-1
Gas Resource Potential – Western Canada Sedimentary Basin
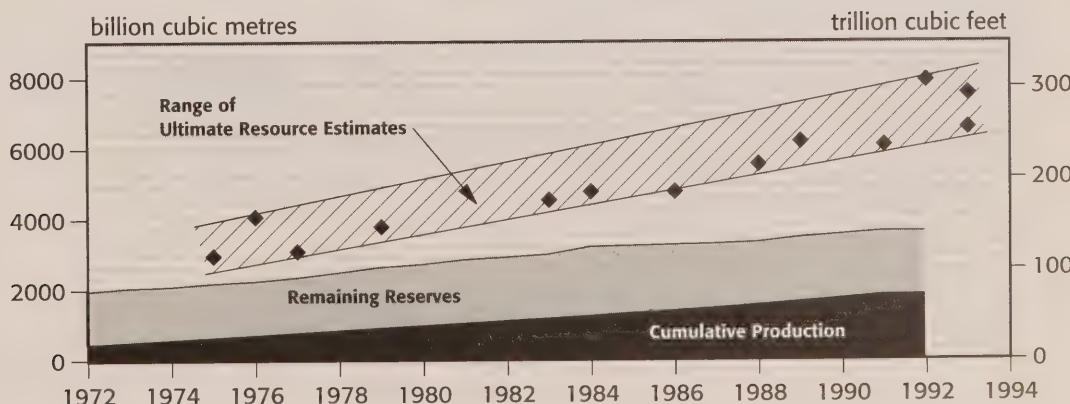
cumulative resource triangle is done in such a way as to exhibit an overlap. For instance, some small conventional gas pools may have a supply cost that far exceeds the development of some of the coalbed methane resources. Similarly, large remote gas fields in the frontier areas are likely to have supply costs and transportation charges that exceed both the smaller pools or the unconventional resources within a mature basin.

The base of the triangle, although finite, is difficult to estimate. However, it is reasonable to conclude that the in-place resource base for Canada is immense.

The Board's resource estimates are selected at a slice of the resource triangle which takes into account current and immediately foreseeable technology, and current geological models and analyses based on the most recent drilling information and statistics. The estimates are therefore made at a snapshot in time confined by the assumptions assigned to the projection period. As noted in Figure 6-1, gas resource estimates have increased over the past twenty years, and will likely continue to increase over time. The linkage between the resource estimate and the underlying assumptions for supply cost and technology is an important concept when comparing Board estimates to estimates available from industry or other government agencies.

The Board's ultimate marketable gas resource is made up of cumulative production, discovered gas (remaining established reserves in WCSB and discovered resources in the frontier areas), undiscovered conventional resources, and current estimates for unconventional resources.

For discovered gas pools in the WCSB, the Board adopts the term remaining established marketable reserves. **Established reserves** are that part of the discovered resource base that is estimated at a point in time to be marketable using known technology under **present and anticipated economic conditions**. Included in established reserves are proven reserves, plus a portion of the probable reserves.

In Canadian frontier basins, only two fields in the southern Yukon and Northwest Territories that are currently on production, have established reserves. The resources in all other frontier discoveries are referred to as "discovered resources". **Discovered conventional resources** in this category are those regarded as potentially marketable using known technology but which are not regarded as established reserves because of undetermined commercial viability. Most discoveries would require the development of significant infrastructure such as a major gas pipeline or offshore structures and facilities to bring them to market. Discovered resource estimates are subject to more uncertainty than established reserves.

For unconventional resources, the assignment of established reserves or discovered resources is even more difficult, given the nature of the resource. Essentially, any reserves or discovered resource estimate is tied to the design and operation of the individual

FIGURE 6-2
Resource Triangle
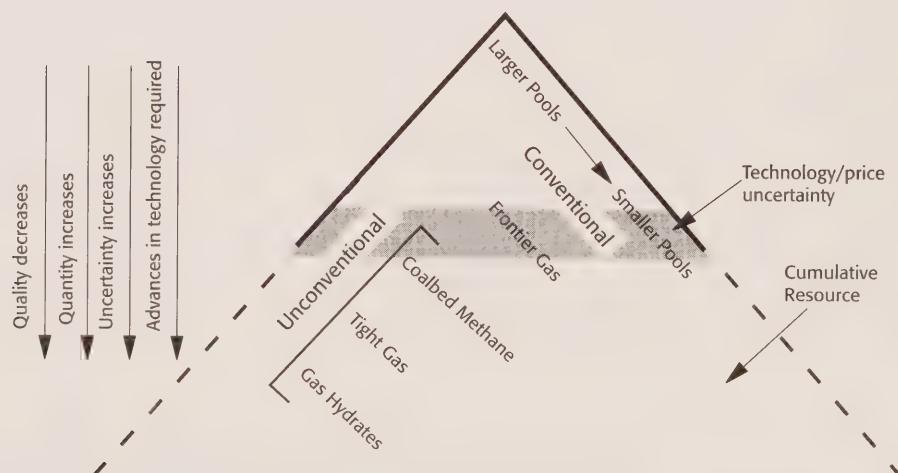
Adapted from: Gray, J.K., 1977, Future Gas Reserve potential, Western Canadian Sedimentary Basin, Third National Technical Conference, Canadian Gas Association.

project and takes into account the anticipated performance of the unconventional reservoir and the number of producing wells. Accordingly the term "project reserves" is used and it is the equivalent of the established reserves for the conventional resource.

The term **undiscovered gas resources** applies only to conventional gas resources. These resources are estimated, at a point in time, to be marketable from accumulations that are believed to exist on the basis of available geological or geophysical evidence, but have not yet been shown to exist by drilling. These estimates are based on the application of known or foreseeable technology under current and anticipated supply costs. Both extensions to currently established pools and new discoveries are included in this category. These estimates carry a significant degree of uncertainty, and thus can be expected to have a wide range depending on the level of technology applied and the amount of geological information available at the time of the estimate.

Undiscovered gas resources is a term applied to both the WCSB and the Canadian frontier basins. It should be noted that in frontier resource assessments, the estimates are often quoted for raw gas, as opposed to marketable gas. However, recognizing the uncertainty associated with frontier estimates, and recognizing that often frontier gas resources contain only limited byproducts, the estimates for the frontier, are tabulated with estimates from the WCSB as marketable gas.

Each component of the resource base is dynamic, that is subject to change through time, as represented in Figure 6-3. As technology advances, supply costs tend to decline, or as prices increase, gas is added to the undiscovered gas resource category from the in-place natural gas resource base. As gas is discovered and assessed through new drilling, resources move from the undiscovered category to the discovered category, either as established reserves in the WCSB or as discovered resources in the frontier basins. Finally gas, as it is produced, is moved from the established reserves category to cumulative production.

Unconventional resources move from the in-place resource base to the marketable **unconventional gas** resource category, through the application of new technology or supply cost reductions. Once the unconventional project has been identified, project reserves are assigned, and following development drilling, are added over time to cumulative production.

Figure 6-1 provides an historical observation of ultimate resource estimates for the WCSB over a twenty year period. The observed increases are an illustration of the dynamic character of the resource base. Based on this, the concept of a fixed resource base, which could in time serve to limit the availability of gas resources, is not appropriate.

The proven reserves category is used in the United States. This is in contrast to a combination of proven and probable reserves in the "established reserves" category

FIGURE 6-3
Dynamic Resource Base
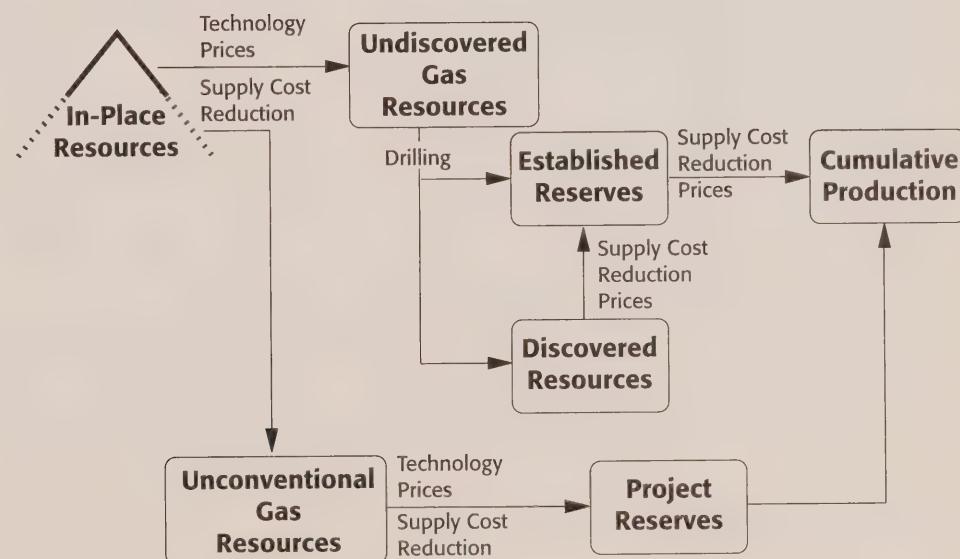
in Canada. The Energy Information Administration (EIA) defines proven reserves as "those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under **existing economic and operating conditions**."

Part of the difficulty in evaluating discovered resources or reserves in the United States is the lack of consistent and well maintained, publicly available reserves data. Estimates published by the EIA are based on field estimates reported by the industry. Unfortunately, unlike Canada, detailed reserves data are not as readily available in the United States or Mexico.

For North American basins outside Canada, the methodologies for estimation may vary greatly; however the basic components are similar. Where possible, the Board uses similar terminology and has applied a similar approach.

6.2.2 Canadian Marketable Gas Resources

6.2.2.1 Initial Discovered Conventional Gas

Initial discovered marketable conventional gas consists of cumulative production, remaining established reserves and discovered resources (Table 6-1). The Board's estimate for the WCSB is 4.1 trillion cubic

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TABLE 6-1
Marketable Conventional Gas
(Billion Cubic Metres)

	Cumulative Production[1]	Remaining Reserves[1]	Discovered Resources	Initial Discovered	Undiscovered Resources	Ultimate Resources
Western Canada Sedimentary Basin						
Alberta	1 832	1 586	-	3 418	2 127	5 545
British Columbia	252	238	-	490	940	1 430
Saskatchewan	71	79	-	150	62	212
South YT / NWT	8	6	-	14	15	29
Sub-Total (WCSB)	2 163	1 909	-	4 072	3 144	7 216
Frontier And Other						
Territories[2]	-	-	19	19	279	298
Mack/Beaufort	-	-	362	362	1 575	1 937
Nova Scotia	-	-	154	154	362	516
Grand Banks/Lab	-	-	245	245	1 032	1 277
Arctic Islands	-	-	407	407	2 269	2 676
Other Frontier[3]	-	-	-	-	2 538	2 538
Ontario	32	9	-	41	-	41
Sub-Total (Frontier and Other)	32	9	1 187	1 228	8 055	9 283
Total for Canada	2 195	1 918	1 187	5 300	11 199	16 499

1   Cumulative Production and reserves as of 31 December 1992.
2   Excludes that portion assigned to the Western Canada Sedimentary Basin.
3   Other Frontier includes: Georges Bank, Laurentian Basin, E. Newfoundland Basin, S. Grand Banks, Maritimes Basin, Hudson Bay, Baffin Bay, and offshore British Columbia.

Sources: WCSB production and reserves from provincial agencies and NEB.
          Frontier and Other production, reserves and resources from NEB, CNSOPB and CNOPB.
          Undiscovered resource estimates: All estimates are NEB 1993, however studies by the provincial agencies and Geological Survey of Canada were used in deriving estimates.

See Table A6-17 for imperial units.

metres (143.8 Tcf) and for the frontier and other Canadian basins is 1.2 trillion cubic metres (43.3 Tcf), totalling 5.3 trillion cubic metres (187.1 Tcf) of conventional discovered marketable gas.

Cumulative Production

Cumulative production of natural gas to 31 December, 1992 from the WCSB, amounts to 2.2 trillion cubic metres (76.4 Tcf). Included with this estimate is production from two fields in the southern Yukon and southern Northwest Territories, which are geologically part of the WCSB. The other producing area of any significance is Southern Ontario with cumulative production of 32 billion cubic metres (1.1 Tcf). The total for Canada is 2.2 trillion cubic metres (77.5 Tcf), 98 percent of which was produced from the WCSB.

Remaining Established Reserves

Estimates of remaining established reserves of natural gas were compiled from assessments and studies of individual pools by Board staff, industry studies and estimates from provincial agencies. The Board's estimate of remaining established reserves for the WCSB, to 31 December, 1992 is 1.9 trillion cubic metres (67.4 Tcf), which includes 6 billion cubic metres (0.2 Tcf) of established reserves in the southern Yukon and southern Northwest Territories. Remaining established reserves for other areas in Canada include 9 billion cubic metres (0.3 Tcf) of remaining established reserves in southern Ontario. The total for Canada is 1.9 trillion cubic metres (67.7 Tcf), 99 percent of which is located in the WCSB.

For the WCSB, a large portion of the remaining established reserves component is found in unconnected pools. The National Energy Board recognizes 595 10^9m^3 (21.0 Tcf) of Initial Marketable Reserves (IMR) of unconnected gas in over 15 600 pools in the WCSB. There are many reasons as to why these reserves are not on production. Until recently, demand for natural gas was insufficient to justify connection of many of these pools. Other reasons include: distance from infrastructure, limited access, or lack of sour gas facilities.

The National Energy Board has been concerned that current IMR estimates in unconnected gas pools are overstated and of questionable economic viability. The issue has been raised in technical consultations with the upstream petroleum sector, other government agencies, and in a recent industry survey conducted by the Canadian Energy Research Institute (CERI).

The Board no longer considers 0.3 trillion cubic metres (11.3 Tcf) of established reserves assigned to a collection of discoveries in the Mackenzie Delta/Beaufort Sea to be established reserves. In the absence of a firm proposal to develop these gas resources, these volumes are now transferred to the category of discovered resources.

Discovered Resources

Discovered resources, as previously defined, are estimated for the gas resources in significant discoveries in frontier regions. The Board has adopted estimates of discovered resources of the Canada-Nova Scotia Offshore Petroleum Board for Nova Scotia, and of the Canada-Newfoundland Offshore Petroleum Board for Newfoundland and Labrador. For other frontier regions, the Board has relied on its own estimates, which are partly based on studies by the former Canada Oil and Gas Lands Administration (Table 6-1). The Board recognizes that methods of estimation used to determine discovered resources differ between agencies, and that resource figures may not be strictly comparable.

Discovered resources total 1.2 trillion cubic metres (41.9 Tcf). This figure includes a slight upward adjustment for discoveries in the Northwest Territories and Yukon, based on new estimates of discovered resources recently released by the NEB[3]. Elsewhere in the frontier, no new gas discoveries and no revisions to previous estimates have been made. The total now includes the aforementioned Mackenzie Delta/Beaufort Sea discovered resources.

Pool Size Distribution

Pool size distribution of past discoveries is an important consideration in evaluating the future potential and the pool sizes to be expected. The larger pools tend to be discovered in the early stages of exploration, while later discoveries are, on average, smaller. In the Western Canada Sedimentary Basin there are approximately 26 900 gas pools (including non-associated and associated), with initial established marketable gas reserves of 4.1 trillion cubic metres (143.8 Tcf), for an average pool size of 151 million cubic metres (5.3 Bcf). Table 6-2 illustrates the historical distribution of pool sizes, and shows the portion of marketable gas that occurs in a relatively small number of larger pools. For the undiscovered gas resources it is expected that the

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3   Probabilistic estimates of hydrocarbon volumes in northern Canadian frontier discoveries NEB Release 93-46, 16 September 1993.

average pool size will likely be in the range of 28 to 57 million cubic metres (1 to 2 Bcf).

6.2.2.2 Undiscovered Gas Resources

Estimates for undiscovered conventional gas resources often display a wide range. Each estimate is expected to change over time with the development of new technologies, increase in geological or geophysical knowledge, or the range of expected supply costs. The estimates provided represent the marketable gas portion of the undiscovered resource.

In arriving at estimates for undiscovered conventional resources, the NEB considered several sources. First, Board staff consulted with over 30 producers, aggregators, pipeline companies and various government agencies in both Canada and the United States. These discussions were conducted to obtain estimates and current understanding of the natural gas resource base and to review issues related to resource determinations and methodology and associated deliverability concerns. Second, the Board considered recent studies on undiscovered natural gas potential. The report by the Alberta Energy Resources Conservation Board, "Ultimate Potential and Supply of Natural Gas in Alberta", as well as recently published estimates and discussions with the Institute of Sedimentary and Petroleum Geology, a subdivision of the Geological Survey of Canada were of particular importance in arriving at Board estimates. Finally, the Board uses its own internal analysis based on a probabilistic methodology.

The Board estimates the marketable component of the undiscovered gas resources in the WCSB (Table 6-1) to be 3.1 trillion cubic metres (111 Tcf). This total is comprised of 2.1 trillion cubic metres (75.1 Tcf) for Alberta, 0.9 trillion cubic metres (33.2 Tcf) for British Columbia, 62 billion cubic metres (2.2 Tcf) for Saskatchewan and 15 billion cubic metres (0.5 Tcf) for areas of the Yukon and Northwest Territories which fall within the WCSB.

For frontier regions, the Board reviewed estimates of ultimate recoverable resource potential published by the Geological Survey of Canada. These estimates are usually expressed as ranges with associated probabilities of occurrence. For purposes of aggregating resource estimates, the average expectation (mean) was selected. The undiscovered portion of the estimate was approximated by subtracting the current total of discovered marketable gas resources from the ultimate potential estimate.

Although estimates of frontier potential are subject to great uncertainty, estimates for areas which have seen minimal exploration and lack confirming discoveries are more speculative than those for areas that contain oil or gas discoveries. Also there is greater uncertainty associated with estimates of potential which are based on unproven or conceptual plays. Basins without confirming discoveries are therefore aggregated as "Other Frontier Basins", found in Table 6-1. In terms of timing of development, such areas fall beyond the time frame for this report.

The Board estimates that the marketable gas portion of the undiscovered conventional resources in the frontier regions is 8 trillion cubic metres (284.3 Tcf). This total includes 5.5 trillion cubic metres (194.7 Tcf) in basins with existing gas discoveries, and 2.5 trillion cubic metres (89.6 Tcf) in basins with no existing gas discoveries.

TABLE 6-2

Distribution of Discovered Initial Marketable Gas Reserves

	Prior to 1980	1980 – 1992	Total	
All Pools				
Number of Pools	13 780	13 110	26 900	
Initial Reserves ($10^9 m^3$)	3 354	720	4 074	
Ave. Pool Size ($10^6 m^3$)	243	55	151	
Pools > 2.8 $10^9 m^3$ (% of Total)				
Number of Pools	186	9	195	(0.7%)
Initial Reserves ($10^9 m^3$)	2 048	82	2 130	(52%)
Ave. Pool Size ($10^6 m^3$)	11 011	9 111	10 923	

See Table A6-18 for imperial units.

Comparisons to Other Estimates

The Board has assessed estimates made by other expert organizations for comparison purposes. For Alberta, the Board's estimate of potential is 2.1 trillion cubic metres (75.1 Tcf), which compares closely with the 2.2 trillion cubic metres (77 Tcf) of undiscovered resources estimated by the ERCB for Alberta in their recent study. The methodology adopted by the ERCB is based upon a section-by-section assessment of the reserves discovered in defined geological plays across the province. This analysis is extrapolated to undrilled sections taking into account geology, reservoir yield, anticipated exploration successes and risk.

The methodology used by the GSC[4] does not readily allow for the dissemination of the undiscovered resources by province, as its estimates are generally published on a basin by basin basis. The published reports usually provide in-place estimates, rather than marketable estimates. Although these reports and discussions with GSC geologists are important to the Board in its analysis of the resource base estimates, some licence was taken, and adjustments made in using the GSC's published results in determining the undiscovered marketable resource component.

The Board recognizes that there are other estimates based upon differing methodologies, which yield a different undiscovered resource potential. A study by Sproule in April 1993[5] infers an ultimate resource potential of 8.7 trillion cubic metres (307 Tcf) compared to the NEB's 7.2 trillion cubic metres (255 Tcf) for the WCSB. This estimate is based upon an analysis using historical extrapolations of reserves additions per foot of hole drilled and an estimate of ultimate drilling.

The National Petroleum Council, an advisory body to the U.S. Department of Energy, completed a gas study[6] for the Lower-48 states, Canada and Mexico based on the assumed technologies expected to be available by the year 2010, and published its findings in December 1992. Its estimate for the Western Canada Sedimentary Basin undiscovered conventional natural gas potential is 3.8 trillion cubic metres (133 Tcf) (compared to the Board's 3.1 trillion cubic metres (111 Tcf).

Reserves Appreciation – Canada and U.S.

Part of the difference between the estimates made by the Board and the NPC is that the NPC estimate includes 24 trillion cubic feet for reserves appreciation. The reserves appreciation factor measures the expected growth of the reserves estimate for pools or fields through time. In the U.S., reporting of reserves is based on field designations, rather than a pool-by-pool basis as in Canada. As such, U.S. reserves appreciation for a field includes new pool discoveries, deeper pool discoveries and pool extensions. Although the range of estimates assigned to reserves appreciation in the U.S. vary greatly, the overall effect is significant. The impact of reserves appreciation in the Lower-48 states will be discussed in the U.S. resource section.

In Canada, reserves appreciation is through pool infill or pool extensions only. Secondly, the established reserves estimates include the proven reserves plus some portion of the probable category. Accordingly, much of the appreciation potential is accounted for in the established reserves estimates. In Canada, the determination of undiscovered gas resources is often based on reserves estimates for fully or nearly fully appreciated pools. Therefore, the pool size estimates for future discoveries are assumed to be appreciated and hence only a modest reserve growth component is justified.

A recent study by the National Energy Board revealed that the appreciation factor in the U.S. for proven reserves in fields is 8.5 compared to a value of 3.5 for established reserves in pools in western Canada. Additionally, the growth in field reserves takes place over an extended period of time in the U.S. with 80 percent of the growth observed to date reached after 35 years following discovery. In Canada, 80 percent of the appreciation is reached within four years of the original discovery. In fact, a portion of the resource assigned as appreciation in Canada is often recorded at the same time as the original discovery due to the additional drilling that occurs in the one to two year period, prior to the recording of the reserves.

6.2.2.3 Unconventional Resources

The unconventional gas resources in our analysis are restricted to coalbed methane and tight gas reservoirs. Both sources of gas require specialized completion and production techniques. There has been only limited commercial scale development for these resources to date and much of the industry activity is directed towards research or pilot projects. While the Board recognizes that there are substantial volumes of shale gas and

4   Lee, P.J. and Wang, P.C.C. Prediction of oil or gas pool sizes when discovery record is available. Mathematical Geology, v. 17, no. 2, p. 95-113, 1985.

5   TCPL Hearing Submission, GH-2-93, April 1993.

6   National Petroleum Council December 1992. The Potential for Natural Gas in the United States.

hydrates, these are, in our judgement, not likely to be exploited within the study period due to lack of commercial technologies.

Coalbed Methane

Since its last Supply Demand Report published in June 1991, the Board has conducted a preliminary review of coalbed methane resources and activities in Canada. Compared to the United States, where production from coalbed methane is about 1.5 billion cubic feet of gas per day or three percent of U.S. production, coalbed methane development in Canada is still in the experimental or pilot stage.

The **in-place resource** for coalbed methane is immense, considering Canada's large coal resources. The Alberta Research Council has estimated the **in-place** coalbed methane resource to be in the order of 73.7 trillion cubic metres (2600 Tcf) for Alberta alone. A similar study by the B.C. Ministry of Energy, Mines and Petroleum Resources estimates that the **in-place** coalbed methane resources for British Columbia exceed 6.7 trillion cubic metres (235 Tcf).

In its recent report, the ERCB provided a range of **in-place** estimates for coalbed methane in Alberta of 7.1 to 73.7 trillion cubic metres (250 to 2600 Tcf). These estimates were provided in submissions to the ERCB from industry and other government departments. Interestingly, the ERCB did comment that gas prices of $2.00 per gigajoule may be sufficient to yield an acceptable rate of return for coalbed methane development, although they did not quantify the fraction of the coalbed methane resource that could be exploited at that price.

The Board, in its preliminary review of coalbed methane resources, concluded that **marketable** gas resource estimates would have to be made on a coal deposit level rather than a basin level, due to the variation in coal properties and potential for exploitation. All coal deposits were reviewed and criteria were developed to evaluate potential for early development. The criteria chosen to select coal deposits for potential development were: coal thickness greater than 5m; gas content in the coal greater than 7.1 cubic metres (250 cubic feet) per ton of coal; depth of coal seam greater than 500m but less than 1800m; recoverable gas per section of greater than 0.3 billion cubic metres (10 Bcf); the development must be accessible with minimal cost and environmental damage; and finally, the development must have access to existing gas markets.

Using the criteria listed above, the Board has adopted a **marketable** unconventional coalbed methane

resource of 0.6 trillion cubic metres (20 Tcf), representing that portion of the **in-place** resource that could contribute to supply during the projection period. This estimate is limited to the Rocky Mountains and foothills areas of British Columbia and Alberta.

The Board recognizes significant resource potential in the Maritimes as well as on Vancouver Island. However, given limited exploration drilling and pilot production projects in these areas coupled with lack of infrastructure, the Board has not assigned a marketable unconventional resource estimate for these areas at this time. It is expected there will be further review by the Board on coalbed methane developments for the Maritimes and Vancouver Island as local activity increases.

The Board's analysis agrees well with the information obtained from technical consultations between Board staff and industry. Most consultations indicated only limited activity by producers toward coalbed methane developments. Although the consultees provided little enthusiasm for immediate coalbed methane potential, the overall consensus was that coalbed methane projects would be more likely than frontier gas developments due to proximity of good quality resources near existing infrastructure, experience with pilot projects and some encouraging results.

The National Petroleum Council in its 1992 report, estimated coalbed methane resources for Canada to be 3.6 trillion cubic metres (129 Tcf) of gas, assuming some level of advanced technology. This is much higher than the Board estimate of 0.6 trillion cubic metres (20 Tcf), but this may be attributable to the fact that there are significant differences in economic and technological assumptions by the NPC compared to the Board. Additionally, the NPC being a U.S. based agency, has a higher estimate for coalbed methane development, perhaps due to recent successes in the San Juan Basin in New Mexico.

Tight Gas

The Canadian tight gas resource is primarily contained in Mesozoic clastic reservoirs in west-central Alberta and northeastern British Columbia. Tight gas in Canada is generally considered to be gas that is produced from formations having a permeability less than 0.1 millidarcies.

The technical definition of tight gas used in the United States differs from the definition used in Canada. In the U.S. gas from low deliverability wells or from wells in designated tight areas are classified as tight for the purpose of eligibility for the now-cancelled tax credit. As a result, the definition for tight gas is much broader

in the U.S.; gas often classified as tight, in Lower-48 basins, would be classified as conventional gas in Canada.

The tight gas resource in Canada is considered to be at an early stage of development since there are limited commercial operations currently in place. Much of the gas being produced from the tight gas category is in fact flowing out of higher permeability sands or conglomerates which are evaluated as conventional reservoirs. Consultations with industry as well as the recent release by the ERCB, suggest that developments of tight gas resources would require gas prices in the order of $10.00 per gigajoule.

The Board recognizes that some companies are actively engaged in evaluating and attempting to tie in tight gas resources. Significant technological advances, particularly in the areas of massive hydraulic fracing, horizontal drilling or improved completion techniques, could reduce the supply cost in the future. **In-place gas resource** estimates range from 5.0 to 42.5 trillion cubic metres (175 to 1500 Tcf) for Alberta alone, according to the ERCB.

The National Petroleum Council in its recent study assigned 2.5 trillion cubic metres (89 Tcf) of marketable tight gas resources to Canada. As suggested before, the U.S. agency based its analysis on U.S. successes and may be overly optimistic in extrapolating tight gas potential into the Canadian basins.

As a result, although recognizing significant potential in tight gas resources, the Board has not assigned a resource estimate for tight gas. The issue of tight gas resources and applications of hydraulic fracing and horizontal drilling will be reviewed in future studies.

6.2.2.4 Summary

Canada's natural gas resource base, that is the **in-place** inventory of conventional and unconventional gas resources, is immense. The marketable portion of that resource represents only a small fraction of the total. Referring to the resource triangle found in Figure 6-2, the Board's current marketable estimate includes much of the high quality conventional resources.

Without question, in the time frame reviewed by this report, the greatest contribution to gas supply will continue to come from conventional gas resources in the Western Canada Sedimentary Basin. The relationship of cumulative production, remaining reserves, and undiscovered potential for the basin and for each of the producing provinces is illustrated in Figure 6-4. The

FIGURE 6-4

Western Canada Sedimentary Basin – Ultimate Marketable Gas

(billions of cubic metres)
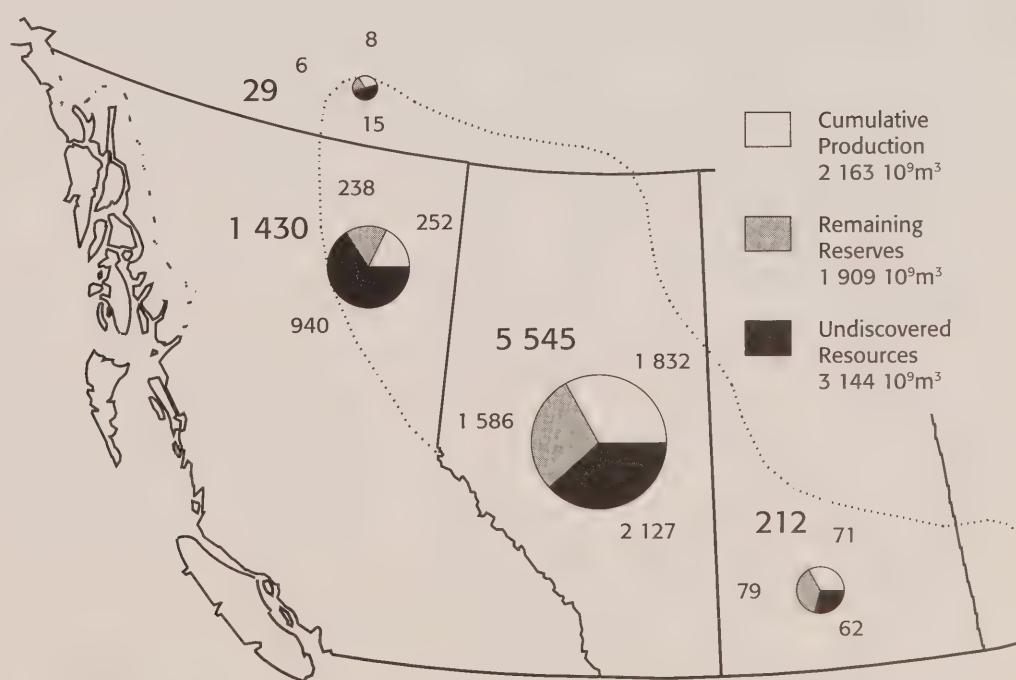
See Figure A6-13 for Imperial units.

Board's total marketable resource potential for the WCSB amounts to 7.2 trillion cubic metres (254.8 Tcf) of which 43 percent remains to be found. Added to this is 0.6 trillion cubic metres (20 Tcf) of unconventional resources in coalbed reservoirs. This suggests that the WCSB will be a reliable source of natural gas for some time to come.

The Board recognizes that resource estimates developed for the report are subject to change in the future. This observation is based on the expectation that future advances in geological knowledge and technology for exploration and production, will result in increased estimates of marketable resource potential in the future. The progressive increases in the estimates prepared through time by respected agencies and experts support this view.

Accordingly, the Board does recognize that there exists a more optimistic view of ultimate marketable gas resource potential, particularly tied to rapid advances in the development and application of new technology to reduce supply or transportation costs. One area where such advances by themselves, or in combination with increases in prices could lead to substantial contributions to supply, would be the Canadian frontier basins.

The Board's total marketable gas resource base for Canada is estimated to be 16.5 trillion cubic metres (582.5 Tcf), of which 56 percent is either discovered or anticipated to be discovered in frontier areas.

It is the Board's opinion however, that frontier resources will for the most part not be developed within the time frame of this report. One exception is the possibility of offshore gas developments in the Scotian Shelf (Offshore Nova Scotia).

Large investments will be required to develop and construct the transportation infrastructure necessary to deliver frontier gas to market. Additionally, these resources would have to compete with the development of unconventional resources in the Western Canada Sedimentary Basin which will also benefit from improved technologies and higher prices. The advantages of frontier gas resources over unconventional developments are their high quality and the fact that once the infrastructure is in place, supply costs for future additions may be substantially reduced. In contrast, unconventional developments would proceed incrementally on a project by project basis. These developments do not necessarily require significant changes to the existing infrastructure, but do incur other costs such as mitigating environmental impact, increased infill drilling requirements and costly completion techniques.

The ideas behind the optimistic view of resource potential and significant advances in technology

provides the basis for the High Technology case in the Board's modelling process. The assumptions supporting this case are discussed later in this chapter.

6.2.3   United States Marketable Natural Gas Resources

In the Board's analysis of United States' gas resources, only the Lower-48 states are considered. Although some adjustments have been made to U.S. resources based on consultations and internal Board assessments, for the most part we have relied on information available in the public domain, particularly that provided by the U.S. Energy Information Administration (EIA) and the Potential Gas Committee (PGC). Since U.S. resources are estimated in imperial units, these are the only units displayed.

6.2.3.1 Discovered Gas Resources

Reserves data for the United States is taken from the Energy Information Administration, Department of Energy, 1992 Annual Report.[7] The EIA's estimate of discovered conventional reserves of dry natural gas for the United States is collected and reported on a field basis, and includes cumulative production and remaining proven reserves. As of December 31, 1992, discovered reserves for the United States were 930 trillion cubic feet. For comparative purposes, in this report, dry gas for the United States is equated to marketable gas for Canada.

Cumulative Production

Cumulative production of dry natural gas from the United States amounted to 775 trillion cubic feet as of December 31, 1992.

Remaining Proven Reserves

At December 31, 1992, remaining proven reserves of dry natural gas for the United States were 155.4 trillion cubic feet. Approximately 83% of these reserves are located in five areas, Onshore Gulf of Mexico (25.5 Tcf), Offshore Gulf of Mexico (25.2 Tcf), Rocky Mountains (37.8 Tcf), Permian Basin (14.5 Tcf), and the Anadarko Basin (27.1 Tcf). These five areas were selected by the Board for more detailed study to determine field size distributions and calculate supply costs for future discoveries.

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7   Energy Information Administration, U.S. Department of Energy, 1993, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1992 Report.

6.2.3.2 Undiscovered Gas Resources

As mentioned earlier, estimates of undiscovered natural gas resources are uncertain, evidenced by the wide range of estimates published by different agencies and the generally increasing estimates over time. This is particularly true for recent estimates of undiscovered gas potential by various U.S. agencies. A comparison between estimates prepared by other agencies and those adopted by the Board is shown in Table 6-3. Although these estimates are all useful for comparison as a U.S. total, only the PGC provides its estimate by basin to allow a detailed comprehensive evaluation of the data. Another source of basin information, used by the Board, although not recent enough to show in the tabulation, is the 1989 United States Geological Survey and Mineral Management Service (USGS/MMS) assessment, "Estimates of Undiscovered Conventional Oil and Gas Resources in the United States – A Part of the Nation's Energy Endowment."

The Board has assessed the various estimates and generally accepted those of the Potential Gas Committee for the purposes of this report. The estimates of the Potential Gas Committee are of natural gas that, "...in the judgement of Committee members, can be recovered by conventional means given adequate economic incentives in terms of price/cost relationships and utilizing current or foreseeable technology." This definition is generally equivalent to the undiscovered gas resources used by the Board.

Estimates were assigned to all PGC geological provinces, and in most cases, the PGC estimate was accepted. In a few instances, estimates by the USGS and/or MMS were adopted. Excluded from the Board's estimate are resource estimates for on-land geological provinces or basins that have no discovered resources, and are not likely to receive any exploration activity in the projection period. Similarly resources in water depths greater than 3000 feet were excluded.

The Board considers an undiscovered conventional gas resource of 492 trillion cubic feet as a most likely case estimate for the projection period. This includes reserve appreciation of 151 trillion cubic feet and new field resources of 341 trillion cubic feet. The estimate

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TABLE 6-3

Comparison of Recent Estimates – Lower 48 United States Natural Gas Resources

(Tcf)

	NPC[2] 1992	PGC[3] 1992	GRI[4] 1993	ENRON[5] 1993	NEB[1] 1993
Cumulative Production	757	757	757	757	775
Proved Reserves	160	158	160	158	155
Initial Discovered	917	915	917	915	930
Reserves Appreciation	203	151	244		151
New Fields	413	423	667		341
Undiscovered Resources	616	574	911	1 145[5]	492
Coalbed Methane	98	78	103		81
Shales	57		127		
Tight Sands	349		241		63
Other	15		43		
Unconventional Resources	519	78	514		144
Total Ultimate Resources	2 052	1 567	2 342	2 060	1 566

1   NEB – Cumulative production and reserves, December 31, 1992, others December 31, 1991.
2   National Petroleum Council, 1992, The Potential for Natural Gas in the United States.
3   Potential Gas Committee, 1992, Potential Supply of Natural Gas in the United States.
4   Gas Research Institute, 1993.
5   Enron Corp., 1993, Outlook for Natural Gas. Breakdown of resource base not available.

of 341 trillion cubic feet is essentially the PGC estimate without the unconventional tight gas resource component (63 trillion cubic feet) and those undiscovered resources assigned to deep water areas or on-land basins with no known discoveries (19 trillion cubic feet).

Approximately 66 percent of the undiscovered new field conventional resource is estimated to be in the five major areas, as shown in Table 6-4, Onshore Gulf of Mexico (33.6 Tcf), Offshore Gulf of Mexico (67.4 Tcf), Rocky Mountains (41.3 Tcf), Permian Basin (33.5 Tcf) and the Anadarko Basin (48.6 Tcf).

Table 6-3 shows the National Energy Board estimate compared to recent estimates by various United States agencies as noted. The estimate is comparable to the Potential Gas Committee; however it is much lower than the others. The Board's estimate is meant to be more of a point in time estimate on the resource triangle, to more directly correspond to estimates made for Canada.

Reserves Appreciation

Recent studies, such as the 1992 NPC Gas Study, highlight the importance of reserves appreciation or reserves growth in assessing the natural gas resource base for the United States. Field reserves in the U.S. can increase through reserves growth from field extensions, new pools, revisions due to infill drilling, improved technology and enhanced recovery. Based on historical data, the cumulative growth factor is inferred to be 8.5, with growth extending over a period of 60 years.

The various estimates for reserves appreciation are shown in Table 6-3. It is important to understand the concepts and quality of the historical reserves data being used, so that estimates that are assigned to reserves growth have not already been accounted for in the undiscovered or new field reserves component. The PGC avoids this confusion by clearly defining the resource categories in their estimation process and summaries. The reserves appreciation estimate adopted by the Board (151 trillion cubic feet) has been extracted from the PGC estimate of probable undiscovered resources.

6.2.3.3 Unconventional Resources

Table 6-3 indicates there is a significant gas resource expected from unconventional sources. This report will only discuss those, that in our opinion, could have an impact within the projection period, i.e., coalbed methane and tight gas sands.

Coalbed methane and tight gas have become important sources of natural gas in the U.S., primarily as a result of incentives from Section 29 tax credits. These credits provided a major impetus to drill and produce unconventional gas; however, the credit terminated at the end of 1992, and drilling activity in these areas has decreased.

The PGC provides an undiscovered coalbed methane resource estimate of 78 Tcf for the United States. We have used the PGC estimates for the various coal bearing regions, and conducted a statistical aggregation, using probabilistic methodology applied to the various resource categories. Using this methodology provides the Board estimate of 81 trillion cubic feet.

The PGC includes tight gas with the conventional resource estimation. The Board agrees with the Potential Gas Committee's estimate of 63 trillion cubic feet of tight gas for the Lower-48 states.

Comparison with the National Petroleum Council Report

The National Petroleum Council in its 1992 report, "The Potential for Natural Gas in the United States," presents an optimistic picture for natural gas. The

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TABLE 6-4
United States Major Gas Areas – Conventional Natural Gas Resources
(Tcf)

Area (Supply Region)	Proved Reserves	Undiscovered Natural Gas Resources		
		< 15,000 ft	> 15,000 ft	Total
Anadarko Region	27.1	35.1	13.5	48.6
Permian Basin	14.5	20.1	13.4	33.5
Rocky Mountains	37.8	27.5	13.8	41.3
Gulf Coast Onshore	25.5	20.3	13.3	33.6
Gulf Coast Offshore	25.2	60.8	6.6	67.4
Totals	130.1	163.8	60.6	224.4

primary conclusion of this study is "The United States has a vast and diverse recoverable natural gas resource base that will continue to grow with time and technology." This view was also supported by several companies during our technical consultations. The NPC ultimate resource total of 2 052 trillion cubic feet compares to the Board's ultimate estimate of 1 566 trillion cubic feet. However the 2 052 trillion cubic feet, when constrained by price, gives much lower results. For instance, in its report the NPC conclude that with today's technology, at a price of U.S. $2.50 per MMBtu, the ultimate resource estimate becomes 1 157 trillion cubic feet, and 1 357 trillion cubic feet at a price of U.S. $3.50 per MMBtu.

Much of the difference between the Board's estimates and those found in the NPC report is evident in the estimates assigned to the unconventional categories. The NPC have 519 trillion cubic feet of gas in the unconventional category, compared to the 144 trillion cubic feet adopted by the Board.

To explain the differences, we need to return to the resource triangle. The NPC report has included more optimistic assumptions regarding supply costs and advanced technology, which could represent a point on the resource triangle further from the apex than that taken by the Board. The sensitivities to this are revealed in the aforementioned differences to the NPC ultimate estimate as a consequence of varying price assumptions.

6.2.3.4 Summary

Current estimates from expert agencies provide a wide range of ultimate gas resources for the Lower-48 states. However, when examined in detail, the wide ranges can be explained by the assumptions regarding technological advancement and supply costs. This is evident in the analysis of the recent National Petroleum Council study.

The Board has chosen to adopt a more conservative approach in its estimates. The point on the resource triangle taken by the Board which best represents the marketable resources available for exploitation over the projection period takes into account a more conservative estimate of supply costs or technological advances. But as was discussed previously, estimates are expected to grow. The observed increases and dynamic character to the resource base, and not a fixed resource base, is as convincing for the U.S. as it is in Canada. As such, limits to the availability of gas resources, based on a finite resource base, are not appropriate.

To reflect the more optimistic viewpoint, the Board as previously described, has added a High Technology case to its supply modelling procedures.

6.2.4 Mexican Marketable Natural Gas Resources

Reliable, up-to-date information on Mexico is difficult to obtain. Since the late 1970s the Mexican Government has ceased publishing any detailed statistics on Mexican reserves and production. The only information released on a regular basis is the estimate of remaining reserves of oil and gas for the country. Natural gas estimates are given on an oil equivalent basis, and this is converted at 6 thousand cubic feet per barrel.

6.2.4.1 Discovered Conventional Resources

The estimates for Mexico have been gathered from published sources such as Oil and Gas Journal, World Oil, AAPG, and Mexican press releases. Table 6-5 provides the estimates being used by the Board for the three producing areas of Mexico. Total discovered recoverable natural gas at the end of 1991 is 104.2 trillion cubic feet. This compares with the NPC estimate for Mexico of 105.9 Tcf.

Cumulative Production

Cumulative production of natural gas for Mexico to December 31, 1991 is estimated to be 34.0 trillion cubic feet, with 21.3 tcf (63 percent) from the southeast. In 1991, 87 percent of Mexico's gas production was from the southeast and offshore areas, generally in conjunction with oil production.

Remaining Proven Reserves

Remaining proven reserves for Mexico are estimated to be 70.2 trillion cubic feet as of December 31, 1991. It should be noted that 74 percent of Mexico's proven gas reserves are in the southeast, and that these are almost entirely associated gas.

6.2.4.2 Undiscovered Resources

The Board is not aware of any recent estimates of undiscovered natural gas for Mexico. It used published estimates by the U.S. Geological Survey for Southeast and Central Mexico[8]. For Northeast Mexico the Board made its own estimate based on information contained in a USGS report[9] on this area. The undiscovered natural gas resource for Mexico is estimated to be 157.2 trillion

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8   Peterson, J.A., 1983, Petroleum Geology and Resources of Southeastern Mexico, Northern Guatemala, and Belize, U.S. Geological Survey Circular 760.

9   Peterson, J.A., 1985, Petroleum Geology and Resources of Northeastern Mexico, U.S. Geological Survey Circular 943.

cubic feet. This compares with the National Petroleum Council estimate of 180.0 trillion cubic feet. The discovered reserves for northeast Mexico comprise 16 percent of the total, whereas this area is estimated to have a larger proportion, 44.7 trillion cubic feet (28 percent), of the undiscovered gas resource.

There is no information available on unconventional gas resources for Mexico, and no estimate has been made. It is reasonable to assume that Mexican unconventional gas resources will have no significant impact for the projection period.

6.2.4.3 Summary

Natural gas resources for Mexico are comparable to the volumes present in the Western Canada Sedimentary Basin. Therefore the potential exists for Mexico to supply significant volumes of natural gas to the now deregulated North American gas markets, sometime within the projection period.

6.3 TECHNOLOGY AND GAS SUPPLY COST

In this report, we examine the impact of technological advances on the cost of finding and developing gas resources. It can be shown that since the early 1980's the unit cost of finding and producing gas has declined in Alberta and British Columbia (Figure 6-5). Much of this recent decline in supply cost may be due to the decline in commodity prices since 1986. That is, cash flow reductions cause only the better prospects to be drilled, thereby reducing the demand, and hence the cost for drilling equipment. This may also result in higher success rates at lower costs. Thus apparent reductions in industry finding cost statistics, which are

FIGURE 6-5
Alberta and B.C. Historical Supply Costs

* Costs include exploration and development drilling, surface facilities and operating cost.
Capital costs are based on Calgary Energy Consultants Alberta and BC Finding and Development Costs, September 1993.
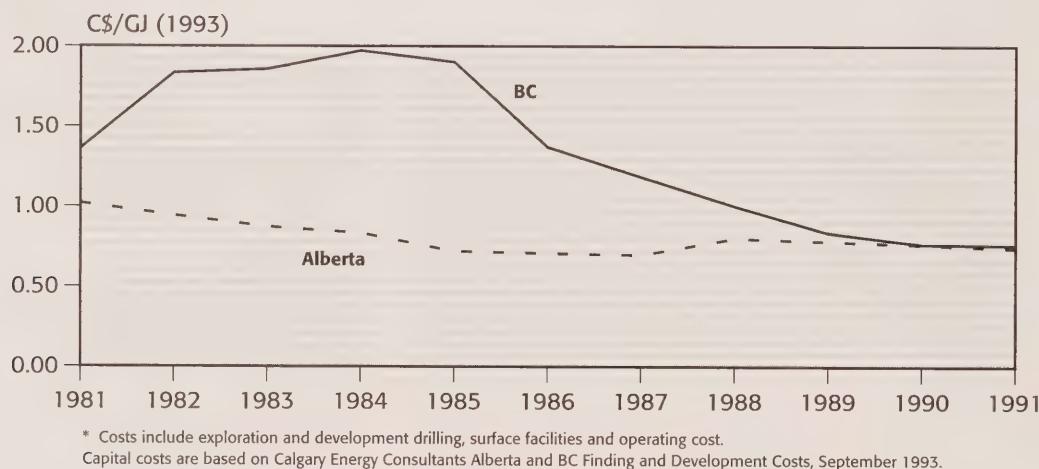
TABLE 6-5
Mexico – Conventional Natural Gas Resources
(Tcf)

Region	Cumulative Production	Proved Reserves	Total Discovered	Undiscovered Resources	Ultimate Resources
Northeast	5.5	11.2	16.7	44.7	61.4
Central	7.2	7.2	14.4	20.0	34.4
Southeast	21.3	51.8	73.1	92.5	165.6
Totals	34.0	70.2	104.2	157.2	261.4
NPC 1992 Report	33.9	72.0	105.9	180.0	285.9

by nature cyclical, can be rationalized, at least qualitatively, on the basis of cost/price relationships and may not represent the impact of technological advances.

Notwithstanding the above, there is little doubt that technological advances have played a role in lowering the finding and development costs of not only natural gas, but of other hydrocarbon resources as well. The effect of technology on supply cost is not well understood in quantitative terms, since it is difficult to isolate the cost reductions due to a particular technology from other factors that also influence cost. Philip Ellis of Booz, Allen & Hamilton[10] suggests that no more than 28 percent of the recent decline in finding costs, is due to technology.

During the consultation process, two views of technology emerged. One view is that the impacts that technology would have on costs and drilling efficiencies would be modest. This view contends that costs would decrease only in certain areas. For example, the frontiers could benefit from technological advances made in offshore or Arctic engineering techniques, largely because there is little experience with this type of development. Unconventional resources such as coalbed methane and tight gas may also be areas in which new technology may lead to substantial advances.

On the other hand, there is a another body of opinion that holds that technology is key to future development through the reduction of supply costs. The arguments put forward are that since resource estimates are directly linked to assumptions pertaining to exploration and development technologies, and recognizing that technology continues to advance, the resource estimates are dynamic in nature. For example, estimates are subject to upward revision as technological advances result in improved and more efficient methods of resource exploitation. These effects are not confined to frontier or unconventional gas, but to all gas resources.

There are two types of technologies that affect the oil and gas industry. The first is referred to as direct technologies, which are those that are specifically related to the exploration, development, production, transportation and marketing of oil and gas. The second group is referred to as indirect technologies, which improve the functioning of the organization such as information systems, management techniques and automated office procedures. It is unlikely that the recent massive corporate restructuring, in both Canada and the United States, could have been achieved without the increased use of indirect technologies. This has had an important effect on overhead costs, but a much smaller effect on total cost, since overhead is now only about 10 to 15 percent of the total. Direct technologies are expected to have a far more significant effect on cost, through improvements in areas such as drilling techniques and new geophysical methods which lead to higher success rates, i.e., fewer dry holes.

It should be understood that any technological development will neither be limited to, nor solely benefit Canadian gas. Technology is pervasive and will not favour any one system, commodity or country over another. However, it may be that certain areas may have better opportunities to exploit these technologies. For example the application of advances in coalbed methane is likely to impact U.S. supply before Canadian supply due to the established production and infrastructure in the U.S. However, for this analysis, it has been assumed that all technologies will impact the U.S. and Canadian supply regions equally.

Examples of recent technological advances include: 3D seismic, slim hole drilling, hydraulic fracturing, polycrystalline drill bits, measurement-while-drilling, horizontal wells and improvements in the process of extraction sulphur from sour gas. These technologies have increased the volumes available and reduced the cost of these volumes by some measure. It is difficult to demonstrate the effect of any single technology, much less measure how effective it is in reducing supply cost. This is mainly due to the fact that technology is not a single event, but rather a combination of events, each at a different stage of evolution and implementation, and that other events, such as swings in oil and gas prices, complicate the analysis.

Established technologies, such as: controlled mud chemistry, unconventional well completions and continuous production tubing are expected to show ongoing enhancements. However, the more important areas may arise from emerging or "undiscovered" technologies. Examples are seismic interpretation of sub-salt plays in the Gulf of Mexico and the ability to drill and economically produce resources from water depths in excess of 3000 feet. The practical application of horizontal drilling has been demonstrated for oil production and gas storage projects and this may well be extended to gas production. Of particular significance for unconventional resources would be development of efficient fracturing techniques for tight gas and methods for accelerated dewatering and water disposal for coalbed methane. High efficiency long distance transportation for natural gas from northern regions, through the use of new

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10 New technology for gas finding: How important has it been? Oil & Gas Journal Sept 30, 1991 (pp 42-44).

pipeline materials and construction techniques, may help to make these resources competitive.

Given that technological improvement is a reality, the challenge is then to determine a reasonable assumption for a rate of advancement and an appropriate method to apply this to the supply cost curve. Technological improvement is usually expressed as a percentage reduction in supply cost per year or cumulative reduction which is used to adjust the supply cost curves at five-year intervals. Views on the rate of improvement vary: Dr. Armstrong, of McGill University, suggests a three percent reduction per year, the Bureau of Economic Geology suggest that six percent is not unreasonable, and the 1992 NPC[11] study adopted four percent per year based on a consensus approach.

With respect to resource estimates, the Board indirectly infers technological improvement and increased geological knowledge through its successive estimates of undiscovered resources and established reserves. In the 1988 report[12], it was estimated that there were approximately 90 Tcf of undiscovered gas in the WCSB. In 1991, this figure had risen to 100 Tcf and is now assessed at 111 Tcf. This implies a four percent increase per year. During the same period, remaining established reserves have fallen only 3.6 Tcf (71.5 to 67.9 Tcf) despite production of some 15 Tcf. Had there been no production in the period 1987 to 1992, the established reserves would have been some 83 Tcf, an implied annual increase of three percent over the 1988 figure. In both these examples, some of the improvement is due to technology, but improved geological knowledge, better data and better estimation techniques have also contributed to the increase.

It would be difficult, and likely serve no useful purpose, to develop a multiple regression analysis to describe the impact of technological improvement as there are many other factors, such as commodity price that impinge on, and likely dominate, the analysis (see Armstrong and Calantone[13]). The Board has therefore assumed an outcome of technology rather than built-up a quantitative rationale. That outcome is assumed to be a flattened supply cost curve. The arguments for this are based on other non-renewable resources, such as coal, tungsten and copper, which have exhibited a flat or declining supply cost over time. In order to recognize this phenomenon, a case has been developed in which natural gas is assumed to behave in a similar manner. It has been labelled the High Technology case, although not all of the improvements reflected in the supply cost will come from technology alone (see 6.4.5 for the supply cost curve).

6.4   SUPPLY COST

6.4.1   Natural Gas Supply Cost

One of the primary inputs into the NARG model is gas supply cost. Since supply cost is the basis for the formation of fieldgate and burner tip prices through the interaction of supply and demand in the market place, it is of great importance that the most reliable calculations, based on the best available data are used.

The methodology for determining supply cost, described in Section 7.1.6, was applied to the principal gas supply regions in both the U.S. and Canada. However, taxes and royalties were not used directly; corporate taxes are calculated in NARG and "user cost" is a surrogate for resource owner royalties and bonus bids for land because these tend to be somewhat market responsive, rather than a fixed ratio of price (Appendix 6.1). Over the past 15 years there have been several modifications to Canadian royalty regimes that have attempted to address the prevailing market situation.

In order to develop a better understanding of the undiscovered gas resource, the Board made estimates of pool size distributions for various regions in the WCSB and the major U.S. supply regions (see 6.2 Natural Gas Resources). These resource distributions were then matched with the appropriate estimates of the costs to find, develop and produce the incremental resource. Western Canada was divided into 11 regions for the geological evaluation: two in British Columbia, eight in Alberta and one in Saskatchewan. These were consolidated into five regions for the NARG input: one in B.C., three in Alberta and one in Saskatchewan. In addition, a coalbed methane supply region was added in B.C.

In the U.S., five regions were examined: Rockies, Permian, Anadarko, Gulf Coast Onshore and Gulf Coast Offshore. These were further divided into shallow and deep formations, and for the Gulf Coast Offshore, shallow and deep water. The gas volume in these regions represents about two thirds of the current NEB estimate of the ultimate potential gas resource for the U.S. (Table 6-3).

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11   National Petroleum Council, The Potential for Natural Gas in the USA. December 1992.

12   National Energy Board, Canadian Energy Supply and Demand 1987 – 2005, September 1988.

13   Alberta Natural Gas Co Ltd, Submission for Hearing GH-6-93 section 4, November 1993.

6.4.2   Inputs for Supply Cost Calculation

The input variables are:

1. Pool size
2. Production profile
3. By-product volumes
4. Capital costs
5. Operating cost
6. Exploration and Development drilling risk.

The anticipated pool sizes were determined by geological analysis of play types in the various regions; each pool class was assigned an appropriate number of exploration and development wells; and probabilities of success and by-product content were estimated. The pool sizes and associated resources are shown on Table 6-6 and Figure 6-6 using the Alberta Foothills region as an example. The production profiles for all gas pools were estimated using an initial remaining reserves to production ratio (RR/P) of 10 and an exponential decline of 10 percent per year. This will tend to overestimate the supply cost for small pools. However, the costs for small pools were so high that it is unlikely these would be a factor in the NARG analysis.

The capital cost data were determined by examining historical costs for the various components since 1986. Sources for this data were Canadian Association of Petroleum Producers (CAPP)[14] Statistical Handbook, Petroleum Service Association of Canada (PSAC)[15] Well Cost Study for Canada, and American Petroleum Institute's (API)[16] Joint Industry Survey for the U.S.

Operating costs were obtained principally from the Alberta Energy Resources Conservation Board's (ERCB)[17] Ultimate Potential and Supply of Natural Gas study for Canada and the API data for the U.S.

Deflators to convert the costs to 1991 dollars are specific to the oil and gas industry.[18]

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14   Canadian Association of Petroleum Producers, Statistical Handbook, September 1993.

15   Winterhawk Petroleum Consultants, Petroleum Services Association of Canada Well Cost Study, 1993.

16   American Petroleum Institute, Joint Industry Survey on Drilling Costs, 1986 – 1992.

17   Alberta Energy Resources Conservation Board, Ultimate Potential for the Supply of Natural Gas, Report 92A, June 1992.

18   Oil and Gas Journal, Energy Statistics Source Book 7th Edition, September 1992.

TABLE 6-6
Estimated Recovery Per Well By Pool Size
Alberta Area 1 Devonian/Mississippian

(Bcf) Size Range	No. of Pools	Mrkt. Gas Potential (Bcf)	Average Pool Size	Average Depth (m)	Recovery Per Well	Wells/ Pool	Explor. Wells	Devel. Wells	Total Wells
< 1	31	14.5	0.47	3 300	0.5	1	62	0	62
1 – 2	22	32.4	1.47	3 300	1.5	1	44	0	44
2 – 5	34	113.0	3.32	3 300	3.3	1	68	0	68
5 – 10	29	210.3	7.25	3 300	7.3	1	58	0	58
10 – 20	25	361.8	14.47	3 300	14.5	1	50	0	50
20 – 50	25	799.4	31.97	3 300	18.0	2	50	38	88
50 – 100	12	856.3	71.36	3 300	25.0	3	24	33	57
100 – 200	6	832.6	138.76	3 300	30.0	5	12	32	44
200 – 500	4	1 110.5	277.62	3 300	40.0	7	8	31	39
500 – 1 000	1	539.6	539.58	3 300	45.0	12	2	14	16
1 000 – 2 000	1	1 020.0	1 020.00	3 300	50.0	20	2	24	26
Total	190	5 890.3	31.00	3 300			380	172	552

Average H_2S Content   0.10
Average CO_2 Content   0.05

The drilling costs for the U.S. and Canada are summarized on Tables 6-7 and 6-8. Geological and geophysical surveys were included at 30 percent of the drilling cost. Field equipment costs ranged from $240,000 to $540,000 per well depending on location. Variable operating costs ranged between $0.38 and $0.85 per Mcf depending on liquids and sulphur content and location. Fixed operating costs varied between $8,000 and $42,000 per well per year. Probability of success for exploration was estimated at between 15 and 35 percent depending on location, depth and pool size. Development probability of success was typically 70 to 80 percent.

The resulting costs were compared to those of the ERCB and those of the National Petroleum Council (NPC)[19] The Potential for Natural Gas in the U.S. Good correlation was obtained with these two published works.

19 National Petroleum Council, The Potential for Natural Gas in the United States, December 1992.

FIGURE 6-6
Future Potential Gas Pool Size Distribution
Alberta Area 1 Dev/Mississ

Estimated no. of Pools		190
Est. Size of Largest Pool(Bcf)		1020
Est. Size of Smallest Pool(Bcf)		0.034

Size (Bcf)	Cum. Prob %	% of Pools	No. of Pools	Future Potential (Bcf)
0.00	100			
0.01	100	0.0	0	0
0.02	100	0.0	0	0
0.05	100	0.1	1	0
0.1	100	0.3	2	0
0.2	99	1.0	3	0
0.5	94	4.3	11	4
1	87	7.5	14	10
2	74	12.8	22	32
5	51	23.0	34	113
10	33	17.7	29	210
20	19	13.9	25	362
50	8	11.3	25	799
100	4	4.3	12	856
200	1	2.2	6	833
500	0	1.0	4	1 110
1 000	0	0.3	1	540
2 000	0	0.1	1	1 020
5 000	0	0.0	0	0
10 000	0	0.0	0	0
20 000	0	0.0	0	0

Median Pool Size (Bcf)	5.53
Average Pool Size (Bcf)	31.00
Future Potential (Bcf)	5 890

Future Gas Pools	>20 Bcf	>50 Bcf	>100 Bcf	>500 Bcf
Number	49	24	12	2
Potential (Bcf)	5 158	4 359	3 503	1 560
Probability (%)	24.0	11.5	6.0	0.8
Average Size (Bcf)	105.3	181.6	291.9	779.8

Future Gas Pool Size Distribution

Gas Pool Potential by Pool Size

Future Gas Pool Size Distribution
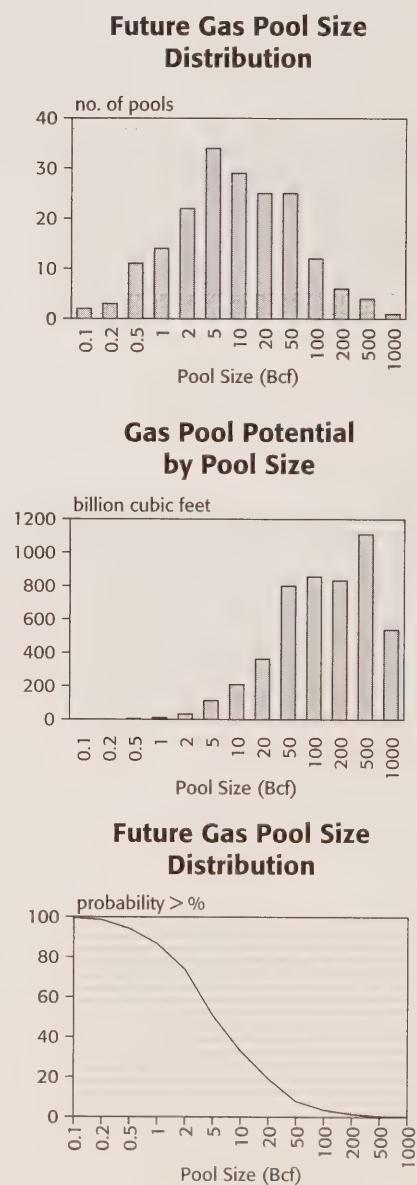
6.4.3   Resulting Supply Cost Curves

The supply cost curves are generated by sorting the supply costs of individual pools for a given region or basin in ascending order of cost, based on the assumption that lower cost (typically larger) pools will be discovered and produced first. The supply cost for individual pools are plotted against the cumulative reserves to produce a supply cost curve. Figure 6-7 shows an example of a resulting supply cost curve for the Foothills region of Alberta. The horizontal component of the curve typically represents the half-cycle cost of developing the remaining established reserves in this area and is relatively low, consisting mostly of operating cost (75 percent) with a modest component of capital cost. Proceeding to the right, the costs become increasingly higher as full-cycle costs are incurred, pool sizes diminish and less resource is added per dollar of expenditure.

Figure 6-8 shows the direct supply cost for Alberta compared to the curve used in the previous report.[20] The methods and assumptions used to calculate the 1991 curves differ from the 1994 analysis. The earlier curves were also based on full-cycle economics; however, only one average drilling, equipping and operating cost was used for each province. An historical decline in the volume of gas discovered per metre of exploratory drilling was developed for each province. These parameters were then used in conjunction with the ultimate resource potential estimates and its relationship to cumulative drilling to calculate supply costs.

U.S. supply costs were previously determined using results generated by the Potential Gas Committee and Geological Exploration Associates. That approach was similar to the method used in this report.

Figure 6-9 shows the comparison of Alberta supply costs to the five U.S. regions evaluated. As can be seen, on a cost basis at the fieldgate, Alberta costs are similar

20   National Energy Board, Canadian Energy Supply and Demand 1990 – 2010, June 1991.

TABLE 6-7

Capital Cost for U.S. Drilling by Region and Depth

US$'000(1991)

Region	Shallow Wells		Deep Wells	
	Av Depth (ft)	Av Cost	Av Depth (ft)	Av Cost
Anadarko	6 769	447	17 060	3 241
Permian	5 193	223	18 462	6 388
Rocky Mountains	6 173	370	16 412	6 532
Gulf Onshore	8 428	784	16 464	4 429
Gulf Offshore	7 230	2 118	16 432	7 690

TABLE 6-8

Capital Cost for Canadian Drilling by Region and Depth

US$'000(1991)

Region		Shallow Wells		Deep Wells	
		Av Depth (ft)	Av Cost	Av Depth (ft)	Av Cost
British Columbia		3 936	598	6 232	567
Alberta	1	7 872	913	10 824	2 403
	2	6 888	813	10 168	1 424
	3	2 624	210	6 396	480
	4	2 132	220	3 280	289
	5	4 920	399	5 904	514
	6	1 312	129	4 264	495
	7	2 592	384	5 576	691
	8	2 296	374	5 576	848
Saskatchewan		1 886	168		

FIGURE 6-7
Supply Cost Curve – Alberta 'A' Foothills

US$/Mcf (1991)

Cumulative Reserves (Tcf)
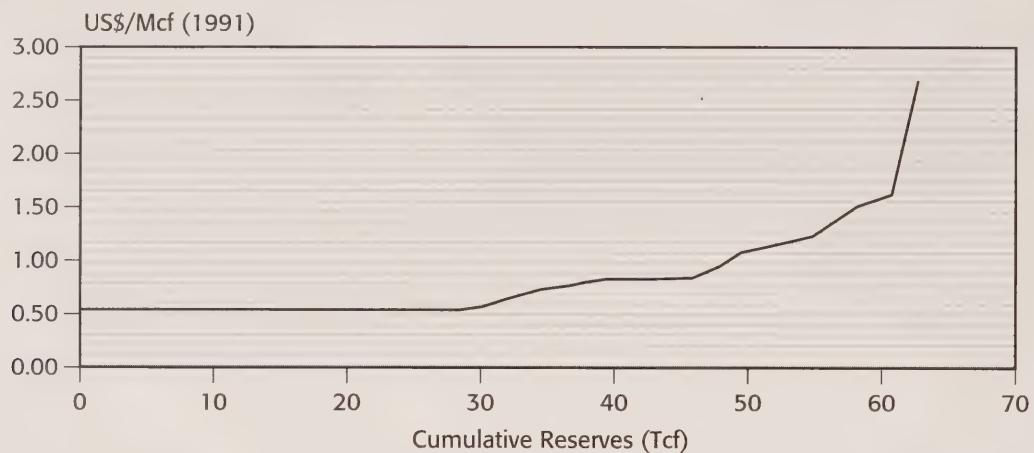
FIGURE 6-8
Alberta Supply Cost Curves

US$/Mcf (1991)

S & D 1991

S & D 1994

Cumulative Reserves (Tcf)
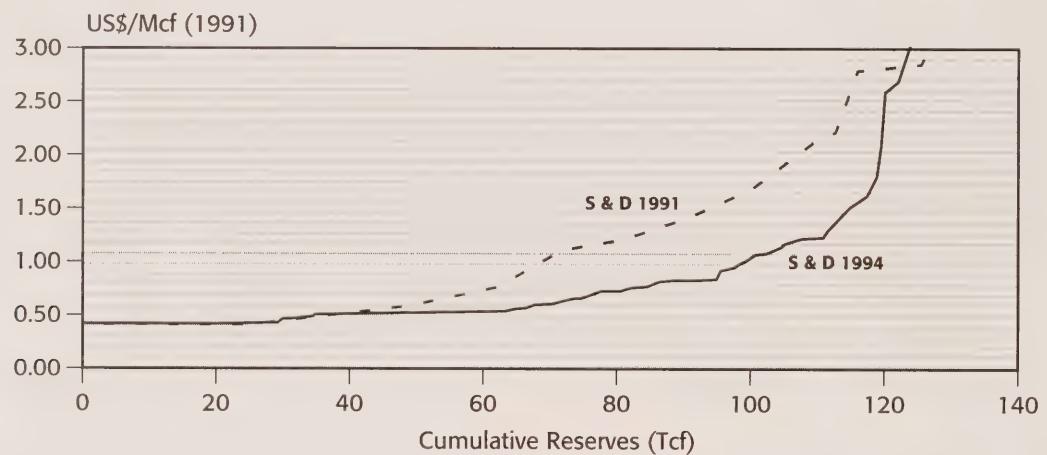
FIGURE 6-9
Comparative Supply Costs

US$/Mcf (1991)

Permian

Rockies

Gulf Offshore

Alberta

Anadarko

Gulf Onshore

Cumulative Reserves (Tcf)
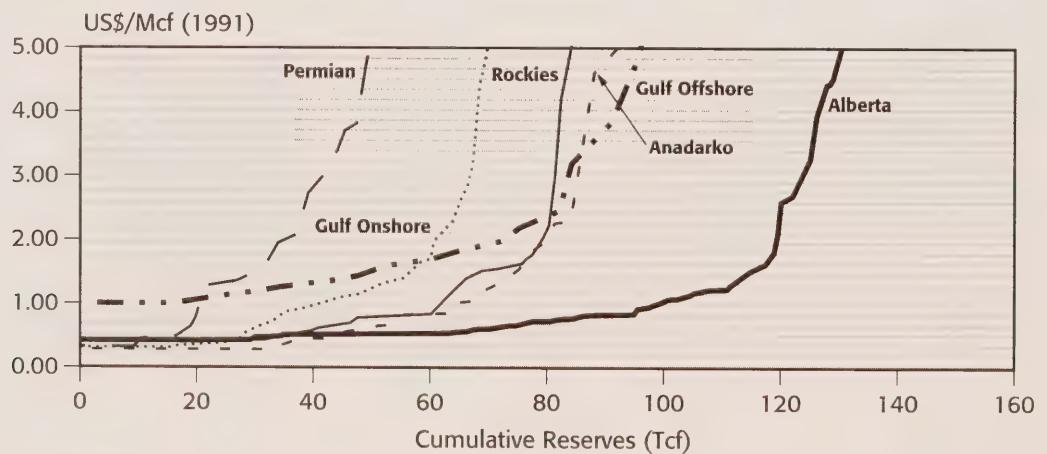
to those for the lower cost U.S. regions, especially through the mid-range (20 to 80 Tcf) of the curve. In order to assess the competitiveness of supply sources in specific market areas, transportation tolls from the producing region to the market region need to be added to the supply costs.

In Canada, the current supply cost estimates show good agreement with those of other agencies such as the ERCB and the Natural Resources Canada, and they are somewhat lower than those used in the previous report. On the other hand, the U.S. results from the five regions analyzed did not exhibit a consistent trend of lower or higher supply cost, when compared to the 1991 results. Therefore the supply costs for the six regions that were not analyzed were not changed for the 1994 NARG analysis.

6.4.4 Supply Costs – Current and High Technology Cases

The resulting curves portrayed in section 6.4.3 were used as the Current Technology supply costs based only on currently known technologies, which are assumed to evolve over time. In order to reflect the body of opinion that technology will have an important effect on supply cost, the analysis was extended to take into consideration possible substantial improvements in technology. In the 1991 Supply and Demand Report this issue was addressed by applying a one percent per year improvement in capital and operating costs. It was also assumed that these costs would decline to 75 percent of the original estimate and remain at that level.

In the High Technology case, a different approach has been used. To obtain these supply cost curves, various rates of technological improvement were examined. The technologies required to achieve this are not specifically identified. It is likely that the improvements will come from major enhancements to existing technologies and from the introduction of technologies that have yet to be identified (Section 6.3). Further, it is possible that advances in geological understanding may lead to the discovery of significant new plays.

Figure 6-10 shows hypothetical declining supply costs based on technologies that may be available in five, ten and fifteen years at an assumed improvement of two percent per year. The half-cycle supply costs for the established reserves, represented by the initial horizontal portion of the curve are not reduced in accordance with the declines inferred by technology because future technology does not result in an immediate cost reduction. To compensate for this we extended the initial horizontal portion of the curve by about 30 percent, representing a two percent improvement per year for the time taken to produce these reserves. The High Technology curve (solid line) is drawn between the 10 and 15 year curves as this represents the approximate duration of production from the current estimate of the established reserves. After the established reserves are produced, supply costs increase as new reserves are found and developed. The increment of capital (sloped portion) is included to account for the change from half-cycle costs in the

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FIGURE 6-10

Hypothetical Supply Curves for Technological Improvement at 2 Percent per Year
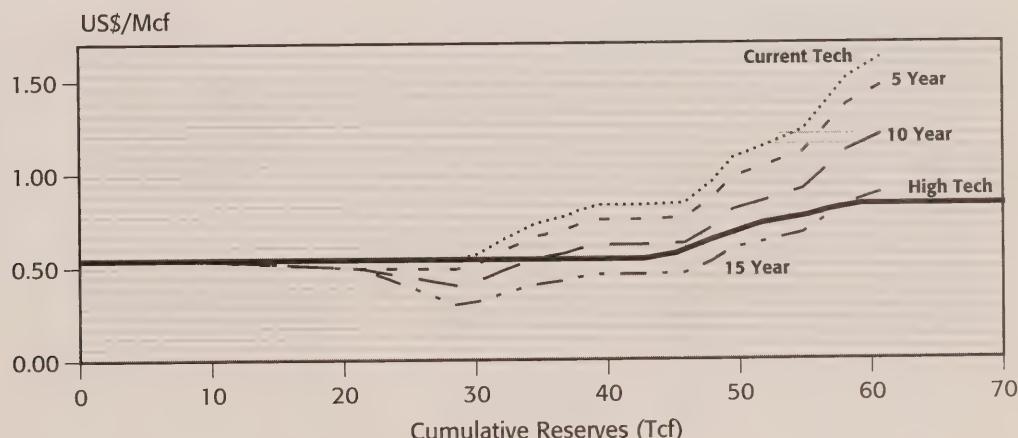
established reserves portion of the curve to full-cycle costs in the remaining portion. The final flat portion of the curve represents the incorporation of new technologies, anticipated to be available in about 20 years, and other factors causing the long-term supply cost to be constant. This is consistent with the assumption that gas behaves like other commodities.

6.5 NARG ASSUMPTIONS

6.5.1 Backstop Price

In order for the NARG model to arrive at a solution, it requires that the "user cost" (Appendix 6.1) in all supply regions be zero within the model's solution period (50 years). It is not always possible to reach the truly optimal solution; however if production from backstop sources exceeds 50 percent of total production then the solution is considered to be within acceptable limits. This occurs when the supply cost plus user cost in a particular region is in excess of the designated level of the backstop price.

The backstop price for this analysis, is defined as the cost at which all the foreseeable demand could be satisfied by a resource that is equivalent to natural gas. US(1991)$5.00 per Mcf has been selected as the backstop supply cost at the fieldgate. This is somewhat lower than the assumption in the previous report of US(1987)$6.00 per Mcf or about $6.75 in 1991 dollars.

Among the sources expected to be available as a "backstop" at this price (particularly in the U.S) are: Tight gas (250-400 Tcf), Shale gas (20-120 Tcf) and Coalbed methane (80-100 Tcf). There are also large volumes of gas available through coal gasification techniques and through imports of liquefied natural gas. Additionally, it could simply be relatively expensive, conventional or frontier natural gas.

It is understood that the backstop price and resource are very uncertain. The uncertainty is exacerbated by this resource not being "required" until after 2011. During the consultation process, there were no strong opinions for a backstop price other than US$5.00. There is a group of opinion that argues the backstop should be geographically specific, i.e., that a different backstop supply source and price would be assigned to each supply region. This concept was not selected because it would unduly complicate the modelling process; it is only applicable where there is a degree of confidence in the backstop supply and it would not properly represent a source that was universally available.

The backstop price will influence the fieldgate price and production volumes. The backstop tends to act as a cap on prices; lower backstop prices would displace supply regions sooner than a higher backstop. While there was not a specific sensitivity undertaken for the backstop price, preliminary results indicated that only minor changes in volumes (about three percent) and minor effects on fieldgate price (two to three percent) would occur within the projection period with a $1.00 per Mcf change in the backstop price.

6.5.2 Liquefied Natural Gas

As noted above, liquefied natural gas (LNG) is one of the potential backstop options. Apart from LNG being used as a backstop supply, import capacity is constrained to about 1 Tcf per year in the NARG model. This represents the total capacity of the four existing terminals (Everett, Cove Point, Elba Island and Lake Charles). Supply costs at these locations are in the range of US$2.70 to $4.00 per Mcf.

Recent studies by the Board indicate that landed LNG supply costs for new facilities would be between US$3.25 and $7.00 per Mcf, absent any return to the gas producers, technological improvement or extraordinary environmental requirements. Thus the value of US$5.00 per Mcf for the backstop price appears to be a reasonable assumption.

6.5.3 Constraints on Switching to Oil

Certain of the market sectors may burn either fuel oil or natural gas. In the electrical generation market, gas fired steam turbines are switchable to heavy fuel oil (HFO, typically No. 4 to No. 6 oil). The cogeneration market, which is based on combustion turbines, is switchable to light fuel oil (LFO, typically No. 2 oil). The industrial market is characterized in a similar way; however, most of the demand is switchable between HFO and natural gas.

The NARG model determines the fuel and the quantity of that fuel which will be consumed on the basis of the relative price of individual fuels. Burner tip prices of both HFO and LFO are determined from the crude oil price projection in Chapter 3 with an allowance for refining and distribution margins.

Oil used in the U.S. switchable market in 1991 was estimated to average 750 thousand of barrels of oil per day (Mbd). For this analysis, HFO market prices are calculated by deducting the historical differential of US$2.60 per barrel from the crude oil price (WTI at Cushing), and then adding regional distribution margins for switchable demand, up to an average of 750 Mbd. If

this demand exceeds the average of 750 Mbd, then a US$5.00 per barrel premium is added to the HFO price to account for additional infrastructure and environmental costs, such as desulphurization. In addition, the price of natural gas must be 10 percent higher than the adjusted HFO price before any switching will occur beyond 750 Mbd.

LFO prices are calculated by using a 35 to 60 percent premium to the crude oil price for the U.S. and a 45 to 75 percent premium in Canada, depending on location. Table 6-9 displays the average prices for LFO and HFO for Canada and the U.S.

The volumes which are included in the switchable market are calculated as a percentage of the demand for gas in the non-core and electrical generation markets. In the U.S., 75 percent of the non-core gas market is assumed to be switchable; in Canada this figure is 25 percent. During the consultation process in Canada and at a recent NEB workshop[21], the 25 percent assumption was strongly supported, and in some cases even thought to be optimistic. The non-core percentage is higher in the U.S. because many more industries have access to both oil and gas, especially oil delivered by water-borne transport. During the U.S. consultations, views were expressed that the 75 percent factor used in the U.S. was high and should be in the 30 to 50 percent range. The analysis incorporates the use of the 75 percent factor because over the long-term, if there is an advantage for HFO versus natural gas at the burner tip, then even applications that are not dual fired may have sufficient incentive to convert. Lowering the proportion of demand that cannot switch to oil may artificially overstate gas demand and prices, particularly in a relatively low oil price environment. All electrical generation natural gas demand was assumed to be able to burn either HFO (steam boilers) or LFO (combustion turbines) as well as

gas. The exception to this was in California where only light fuel oil will be permitted after 1996 as burning of HFO will then not be permitted, due to environmental legislation. LFO is typically not competitive relative to gas.

6.5.4 Transmission, Distribution and Storage

In general, the pipeline network is represented in NARG by corridors rather than specific pipelines. The major exceptions are TCPL, PGT and potential future connections such as Altamont, ANGST and the Mackenzie Delta. Figure 6-11 shows the major corridors between supply and demand regions.

The representation of pipeline tolls approximates the tolling structure that has evolved as a result of recent regulatory changes in the U.S. transportation industry. FERC Order 636, implemented in November 1993, changed the tolling methodology to Straight Fixed Variable (SFV), unbundled tolls and services and allowed capacity brokering. SFV toll design allocates more of the transportation cost to fixed demand charges than the Modified Fixed Variable method previously used. SFV has been common practice in Canada for many years. Capacity brokering, the "selling" of capacity by one shipper to another, can result in the discounting of transportation charges that previously would have been fixed. Unbundling of service has changed the role of the interstate pipeline companies from one of a transporter, marketer and administrator of natural gas to that of a common carrier.

Within the context of NARG, the implementation of FERC Order 636 has had little effect on the analytical approach since the model design provides solutions

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21   Export Impact Assessment Workshop, National Energy Board, April 1993.

TABLE 6-9
Oil Product Prices for the Natural Gas Market Analysis
(US$1991/Mcf)

Canada	1991	1996	2001	2006	2011
LFO	5.69	5.09	5.32	5.59	5.85
HFO Noncore	3.17	2.81	2.92	3.22	3.52
HFO Electricity Generation	3.08	3.81	2.96	3.13	3.27
United States					
LFO	4.95	4.43	4.51	4.59	5.02
HFO Noncore	3.08	2.69	2.82	3.55	3.83
HFO Electricity Generation	3.29	2.79	2.94	3.72	4.50

FIGURE 6-11
Pipeline Schematic

FIGURE 6-11
Pipeline Schematic

N. Alaska

LNG
S. Alaska

N. Canada

B.C.

Alta

Sask

Man

Que

E. Canada

Ont

New England

P.N.W.

N.G.P.

WNC

Mid-Atlantic

Rockies

California

San Juan

Anadarko

ENC

N.Cent

Appalachia

Arkoma

ESC

WSC

S.Atlantic

Permian

LNG

Gulf Coast

Symbol	Legend	Symbol	Legend
◎	Supply Region	———	Existing Pipeline
▦	Demand Region	- - - -	Future Pipeline
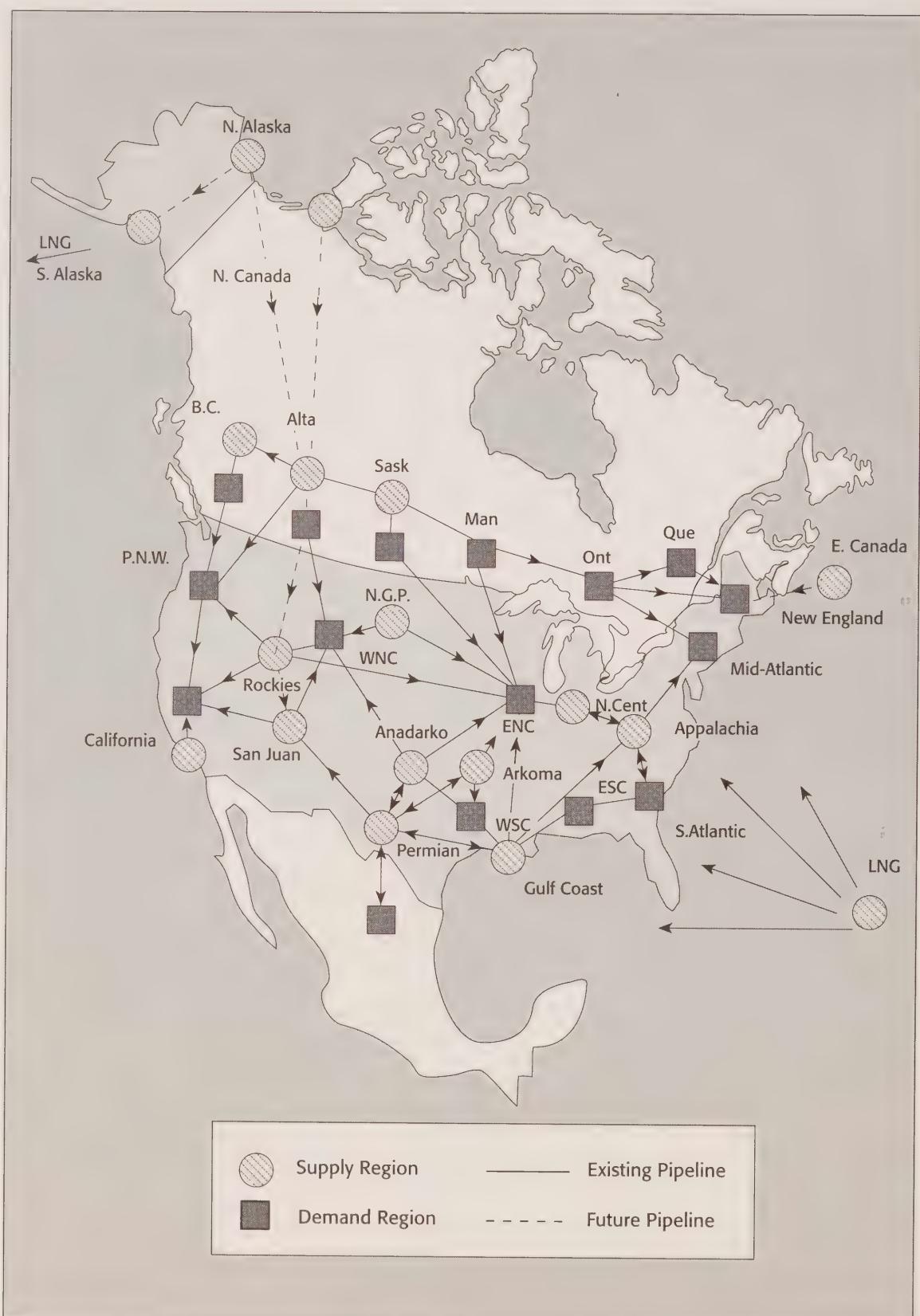
similar to those generated by markets which operate in an unregulated manner.

Toll discounting is not incorporated into the analysis and its impact may not be very significant in a long-term analysis such as this. It could have some short-term effect on the allocation of market share between competing supply regions.

The unit toll used for each link or corridor is fixed in real terms over the projection period, even if the link is expanded. Links are expanded when there is an economic advantage to do so. The rationale for maintaining the same toll on the expanded corridor is that depreciation on the original pipeline link would offset the increased toll on the expanded link.

The pipeline tolls are estimated averages based on work done by the California Energy Commission (CEC) for its 1993 Fuels Report[22]. Historical operational revenues for the pipelines comprising each link were determined and then divided by the historical volumes shipped on each link. This gave a blend of service type (firm, interruptible, etc.) based on actual recorded revenue on the various links. This approach is superior to examining the posted tariffs for different types of service from the constituent pipelines, and then estimating an average toll.

The initial capacity on each corridor was determined from data published by the U.S. Energy Information Administration for U.S. pipelines and by the NEB for Canadian pipelines. Tolls and capacities are shown in Appendix 6.

Distribution margins represent the cost of moving gas from the main pipeline to the end-use customers through the local distribution companies. These costs were estimated for both Canada and the U.S. by comparing historical city-gate prices with historical end-use prices. These were examined by sector (residential, commercial, industrial and power generation) and by demand region. Because power generation uses only small volumes of natural gas in Canada, the industrial distribution margin was used. As with the pipelines, these charges were treated as fixed in real terms over the projection period. Distribution margins are shown in Appendix 6.

It is recognized that storage plays an increasing role in the natural gas market by way of optimizing operation and sizing of pipelines, and reliability during periods of high demand. In the NARG model, the effect of storage is not included since it is assumed that the net flow of gas into and out of storage reservoirs is zero on an annual basis.

6.5.5   Canadian Demand

Chapter 4 provides a detailed description of the Canadian demand projection and its underlying assumptions. NARG demand responses to price changes are modified in the analysis to mirror those of the NEB energy demand model. Primary gas demand is projected to grow from 2.2 Tcf in 1992 to 2.8 Tcf in 2010 in the Current Technology case. For the High Technology case, demand is expected to grow to 3.2 Tcf. The annual growth rates for these projections are 1.3 and 2.2 percent respectively. Growth rates for residential and commercial demand (core) are slightly lower than average in both cases, whereas industrial demand (non-core) shows a slightly higher than average growth. Figures 6-12 and 6-13 show the sectoral demand for both the Current Technology and the High Technology cases respectively.

6.5.6   U.S. Demand

The 1993 edition of the Gas Research Institute (GRI) Baseline Forecast[23] was used as the basis for estimating U.S. demand. The volume projections and demand assumptions, relevant to each sector, are included over the projection period of 1991 to 2010.

GRI provides macro-level assumptions for economic, demographic and institutional variables. GRI projects a real growth rate of 2.1 percent per year and an average inflation rate of 4.1 percent per year between 1991 and 2010. To estimate population growth, GRI uses a modified version of the U.S. Bureau of Census. This approach is used to account for rising immigration. If the use of new technology is considered likely, it is included in its projection. GRI also assumes a largely competitive market with no regulatory changes and an increasing concern and response to environmental protection objectives.

GRI analyzes demand by industry sectors, each of which is broken down by region in the Baseline Forecast Data Book[24]. The NARG model analysis is also done by region, each of which is separated into three market sectors. These are referred to as the core, non-core and

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22 State of California Energy Commission, Fuels Report, December 1993.

23 P.D. Holtberg, T.J. Woods, A.B. Koklauner, and M.L. Lihn, 1993 Edition of the GRI Baseline Forecast of U.S. Energy Supply and Demand to 2010, Gas Research Institute, Chicago, Illinois, June 1993.

24 P.D. Holtberg, T.J. Woods, M.L. Lihn, and A.B. Koklauner, Baseline Forecast Data Book, 1993 Edition of the GRI Baseline Forecast of the U.S. Energy Supply and Demand to 2010, Volume I, Gas Research Institute, Chicago, Illinois, June 1993.

electricity generation markets. The distinctions among the market sectors are based on fuel-switching capabilities.

The core market consists of natural gas consumers in the residential, commercial and industrial sectors that do not have the option of switching between alternative fuels. The non-core market refers to commercial, industrial and non-cogeneration consumers who are able to switch between gas and HFO or LFO. In simulations such as this demand is endogenized to some extent by fuel switching.

The electricity generation market is also switchable; however two additional distinctions are assumed. Steam turbine generators are switchable between gas, HFO and in some cases coal. Combustion turbine and combined cycle generators are switchable between gas and LFO. The latter include commercial and industrial cogeneration because they principally use combined cycle technology. To determine the gas/HFO and gas/LFO switchability for the NARG model, the projections from three organizations are used because no single source provides all of the necessary information. The three organizations are the Gas Research Institute (GRI), the North American Electric Reliability Council (NERC) and the Energy Information Administration (EIA). The procedure involves combining the information obtained from each to determine the relative gas and oil demands. See Appendix 6.2 for a description of the procedure.

Total natural gas consumption is projected to grow modestly from 19.4 Tcf per year (actual) in 1991 to 24.3 Tcf per year in 2010. It is expected there will be

FIGURE 6-12

Current Technology – Canadian Gas Demand
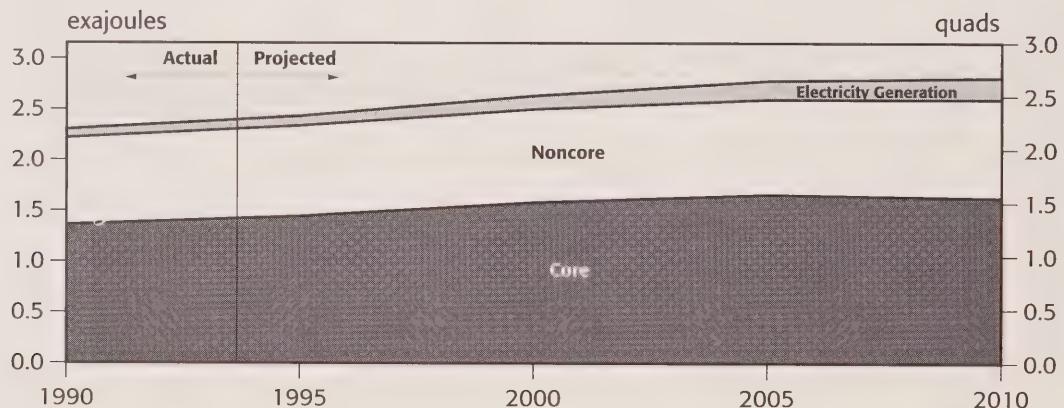
FIGURE 6-13

High Technology – Canadian Gas Demand
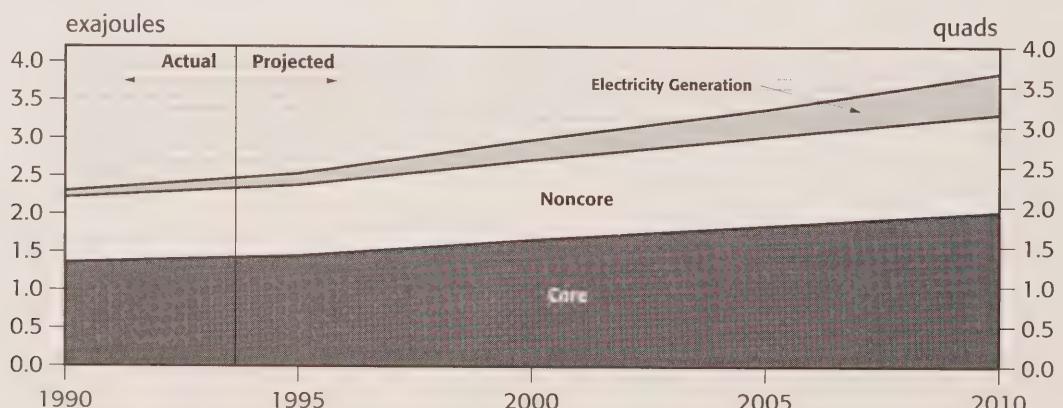
substantial increases in gas demand for the industrial and electricity generation sectors.

For the residential sector, natural gas demand is expected to remain constant at 4.6 Tcf per year. While the number of gas-heated homes is projected to grow, the implementation of efficiency standards is expected to offset the associated growth in natural gas demand. GRI predicts that a gas-fired space-cooling system would provide an opportunity for increasing demand for natural gas; however, the development of such a system is not assumed in the baseline projection. Instead, GRI assumes the introduction of a gas-fired heat pump. In order to maintain the space-heating market share, the efficiencies of gas-fired systems must be competitive with improvements in other systems.

Gas demand in the commercial sector is projected to increase from 2.7 to 3.4 Tcf per year between 1991 and 2010. Potential growth is dependent on the successful introduction of space-cooling and cogeneration technologies. However, improvements in the efficiency of space-heating systems may partially offset this growth.

Industrial gas consumption, including gas consumed in industrial cogeneration, was 8.6 Tcf per year in 1991 and it is estimated to increase to 10.9 Tcf per year in 2010. Industrial consumption is separated into three components: feedstocks, fuel and power. Feedstock demand is a function of the demand for ammonia, hydrogen, and methanol. Fuel and power consumption is affected by business cycle changes and cogeneration demand. The latter is projected to grow from 0.6 to 1.3 Tcf per year.

Natural gas demand for electricity generation includes gas consumed by utilities and independent power producers (IPP); it is expected to increase from 2.8 to 4.1 Tcf per year. This does not include gas used for cogeneration or small power producers (SPP) which is included in the industrial sector. This demand projection is based on a robust outlook for construction plans for new gas-fired generating capacity. Environmental concerns may cause a reduced demand for coal, and thus, increased consumption of gas. Repowering of older capacity is also an option that could increase gas demand.

In the transportation sector, GRI estimates demand will grow from 0.7 to 1.4 Tcf per year. Of this, gas pipeline fuel demand is estimated to increase from 0.7 to 0.9 Tcf per year. Most of the growth in the transportation sector is expected to result from the penetration of natural gas into the vehicle market.

Natural gas demand for vehicles is estimated to be 0.5 Tcf per year by 2010. However, this may be limited by a lack of public refuelling stations. Entry of natural gas in the vehicle market will depend on two factors: public policy requirements for alternative fuels and economics.

6.6   RESULTS AND ANALYSIS

6.6.1   Preamble

The discussion of results will focus on fieldgate prices, production, exports, imports, U.S. demand and inter-fuel competition. The results will be examined in total for both Canada and the U.S. and on a regional basis for prices, production and exports. All prices are 1993 Canadian dollars, unless stated otherwise.

The initial discussion compares the Current Technology and High Technology cases, developed to evaluate the effect of technological progress on the gas supply cost curves. In addition to these base cases, two sensitivity cases have been developed to examine the effects due to higher U.S. gas-fired electrical generation demand and the impact of a new competitive gas supply source on natural gas prices, production and exports.

The following results were generated by the NARG model and should be regarded as indicative of the general trends for each component in the analysis rather than projections of the precise outcomes. It is also noted that these results are valid only for the precise set of assumptions used in the analysis. Furthermore, NARG does not constrain production volumes due to lack of infra-structure, such as gas plants, pipelines and drilling capability, therefore some volume projections may appear to be overstated for particular periods.

The model solves for five-year intervals, and the results are displayed at these points. Since 1991 was the base year, the "result" years are 1996, 2001, 2006 and 2011. All volumes are shown in imperial units as this is the way the model is set up, prices have been converted to Canadian dollars per gigajoule.

The Board acknowledges that there is be some uncertainty surrounding any analysis of trends in natural gas supply and demand. The purpose here is to provide the results for two plausible cases which can be used as reference points for the further discussion of future trends. As noted in the following sections individual market participants may make choices which could vary considerably from the assumptions built into this modelling process. Individual producer or pipeline behaviour is not modelled in this version of NARG and hence is addressed in a qualitative manner.

6.6.2 Current Technology vs High Technology

6.6.2.1 Fieldgate Prices

Figure 6-14 illustrates the anticipated fieldgate prices for both Alberta and the Lower-48 states for both cases. Under the Current Technology assumptions, Lower-48 prices may be expected to increase to about $5.50 per gigajoule in 2011, an average real growth rate of about four and a half percent per year. Alberta prices are projected to escalate at a slightly higher annual rate of about six percent, to approximately $4.50 per gigajoule. In contrast, the High Technology case suggests a Lower-48 annual growth rate of just over two percent after an initial decline, due to the first stage of technological improvement. Prices then rise to $3.30 by 2011. Alberta prices increase in this case to only $2.40 per gigajoule, an average annual increase of close to two percent. For both cases, B.C. fieldgate prices are similar to those in Alberta, being generally a few cents higher, whereas Saskatchewan prices, although showing the same trends, are some $0.30 to $0.60 per gigajoule higher than Alberta.

The rate of increase of prices is higher in Canada than in the U.S. because Canadian prices start at a lower level, as a result of the deliverability surplus that existed until 1992/93. Fieldgate prices are becoming more uniform among regions because the North American gas grid has become more developed and accessible. As a consequence the price differentials will tend to be driven principally by transportation differentials.

In both Canada and the U.S., the High Technology prices are about 45 percent lower than the Current Technology prices due to lower supply costs in that case. As expected, Alberta prices are consistently below Lower-48 prices for both cases, ranging from $0.90 to $1.00 per gigajoule less over the projection period, because WCSB supply costs are generally lower relative to the U.S. producing regions. These price differences are higher than historical averages which have been in the range of $0.30 to $0.70 per gigajoule. In NARG the determination of prices is driven only by the combination of supply cost, user cost and tolls, and hence it does not always reflect real market practices.

6.6.2.2 Canadian Production

Total Canadian production for the two cases is shown in Figure 6-15. In the Current Technology case, Canadian production is expected to increase to 6.5 Tcf/year by 2006, and declines thereafter to 5.8 Tcf/year by 2011. The rate of increase in production to 2006 is greater than the rate of increase in domestic demand alone, due to a rapid increase in exports over that time frame. The decline in production between 2006 and 2011, particularly from Alberta, is the result of a decline in U.S. demand. The primary reason for this loss is that the gas price has increased to the point where it exceeds the price of HFO at the burner tip resulting in gas-to-HFO switching (U.S. Fuel Switching 6.6.2.8).

Total Canadian production in the High Technology case rises to 7.0 Tcf/year by 2011. While the 2011 production is higher than that in the Current Technology

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FIGURE 6-14
Fieldgate Gas Prices

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
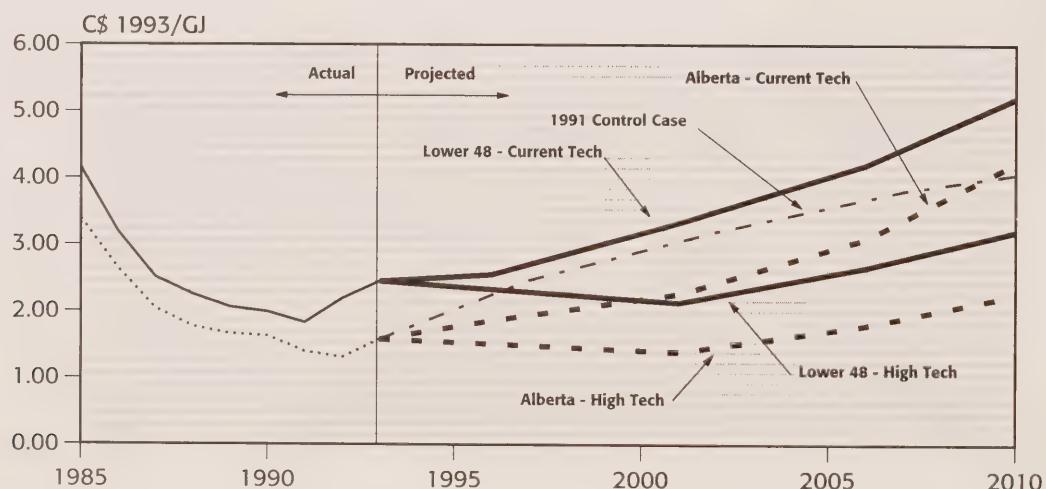
case, in the intervening years it is 0.5 to 1 Tcf/year lower until 2007. In this case the flattened supply cost curves make natural gas more competitive with alternate fuels, and it therefore gains market share. The lower Canadian production, between 1996 and 2006, is the result of export volumes remaining at about the 1993 level of 2.2 Tcf/year. This is because production has also increased in the U.S. due to technology, causing the development of the substantially larger remaining established reserves component 150 Tcf in the Lower-48 versus 70 Tcf in the WCSB. Consequently a greater quantity of lower priced U.S. gas is available to meet the demand, thereby reducing the requirement for Canadian gas in the U.S. market until about 2006.

Figure 6-16 shows the projected production from British Columbia and Alberta for both cases. Gas production from British Columbia for the Current Technology case, grows to 1.4 Tcf/year by 2001 and then remains flat for the balance of the projection period. Alberta production increases to about 5.2 Tcf/year by 2006. Beyond 2006, Alberta production declines to 4.2 Tcf/year. Production in Saskatchewan is projected to remain relatively constant at a level of about 0.2 Tcf/year, throughout the study period.

With respect to frontier supply, a small amount of supply is expected to be produced off the East Coast by 2007 in the Current Technology case, reaching a level of 0.1 Tcf/year by 2011, notionally corresponding to a 300 MMcfd development for Sable Island. Although we recognize that this development would create a local demand for natural gas, we believe that it would be small, relative to the exports volumes; therefore we have assumed that all of the gas would be exported to the U.S. Northeast. The Board understands that there are

FIGURE 6-15

Canadian Production
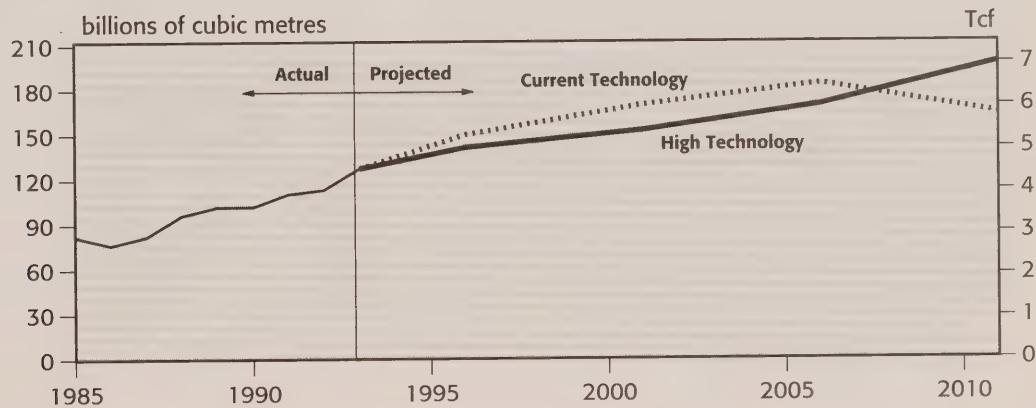
FIGURE 6-16

Alberta and B.C. Production
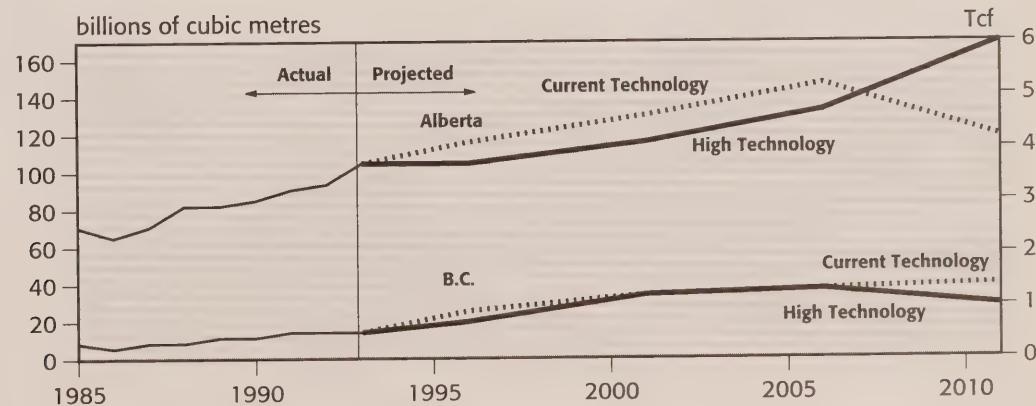
various proposals to convert potential East Coast gas production to electricity and then export the power. However, for this analysis, it was assumed that the export would be natural gas rather than electric power. No production is expected from Northern Canada over the projection period.

For the High Technology case production, from British Columbia is expected to increase to 1.3 Tcf/year by 2006 and then decline to 1 Tcf/year by 2011. Over the projection period, Alberta production is projected to rise from 3.2 to 6.0 Tcf/year. As in the Current Technology case, Saskatchewan production remains constant at about 0.2 Tcf/year, and there is no production expected from either Northern Canada or the East Coast because there is sufficient lower cost gas available from the Lower-48 and WCSB to satisfy the North American market requirements, and supply and transportation costs for frontier gas exceed those of the conventional basins.

No significant production is expected from Canadian coalbed methane in either case.

The NARG model results for the High Technology case show B.C. supply declining as Alberta supply increases after 2006, implying that Alberta gas is displacing B.C. gas. In reality, it is more likely that B.C. production would not decline as much and that Alberta production would not rise as much, because the price differential causing this reallocation is small. Also, the model does not take account of toll or price discounting and simply switches between supply sources on the basis of the relative supply cost and transportation toll.

6.6.2.3 United States Production

Lower-48 production follows a similar pattern to that of Canada and is expected to increase to 18.8 Tcf/year by 2006 under the Current Technology case (Figure 6-17) and then decline to 17.5 Tcf/year by 2011. This apparently results from significant inter-fuel competition, which as noted above, decreased the demand for gas and hence the level of U.S. production and imports from Canada.

In the High Technology case (Figure 6-17), Lower-48 production is projected to increase to 21.0 Tcf/year over the projection period. Demand and hence production, is expected to be higher than the Current Technology case because of lower gas prices. Gas, therefore, satisfies more of the energy demand, particularly in the switchable fuels market. Lower-48 production slows somewhat in the latter part of the projection as Canadian imports become more competitive relative to U.S. supply during this period.

Table 6-10 shows that U.S. demand is mainly met by Lower-48 production and Canadian imports, which account for about 85 percent and 13 percent of the demand respectively by 2011, for both cases.

The regional distribution of U.S. production over the projection period is displayed in Figure 6-18 for the Current Technology case. The Gulf Coast share of total U.S. production declines from 55 percent in 1991 to 36 percent in 2001, recovering to about 40 percent by 2011. The share of the market supplied by Rocky Mountain gas increases from six percent in 1991 to 19 percent in 2011. This increase is a result of a combination of lower supply costs and transportation tolls for the Rocky Mountain region, as compared to other U.S. sources, especially the Gulf of Mexico. Anadarko production remains relatively constant at 2.9 Tcf/year until 2006 and then decreases to 1.8 Tcf/year in 2011. The Anadarko region's market share drops from 18 percent in 1991 to 10 percent in

FIGURE 6-17
U.S. Lower-48 Production
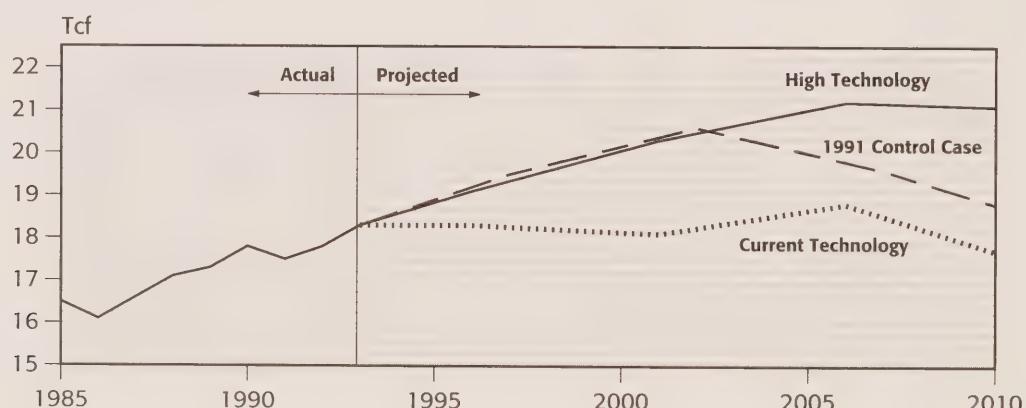
2011 as a result of its displacement by Gulf Coast gas in the latter part of the projection. Production from the Permian Basin rises to 1.6 Tcf/year in 1996 and then declines to 1.3 Tcf/year. That region's market share remains constant over the projection period at about seven percent. After 2006, much of the decline in gas production reflects loss of demand due to fuel switching.

The regional distribution of production for the High Technology case (Figure 6-19) shows variations, which while similar in shape to the Current Technology case, are somewhat more muted. In the Gulf Coast, a decline to 6.6 Tcf/year between 1991 and 2001 is expected, after which production should rise to its 1991 level of 8.3 Tcf/year by 2011. Production from the

TABLE 6-10

Composition of U.S. Gas Supply

Tcf/Yr

	Current Technology				
	1991	**1996**	**2001**	**2006**	**2011**
Lower 48	15.8	18.3	18.1	18.8	17.5
Alaskan Gas	0.2	0.2	0.2	0.3	0.3
Mexican Imports	0.0	0.0	0.0	0.0	0.0
LNG Imports	0.1	0.2	0.2	0.3	0.3
Net Cdn. Imports	1.7	2.5	3.0	3.4	2.8
Total U.S.+Imports	17.8	21.2	21.5	22.7	20.9
	High Technology				
	1991	**1996**	**2001**	**2006**	**2011**
Lower 48	15.8	19.1	20.3	21.2	21.0
Alaskan Gas	0.2	0.2	0.2	0.3	0.3
Mexican Imports	0.0	0.0	0.0	0.0	0.0
LNG Imports	0.1	0.0	0.0	0.0	0.1
Net Cdn. Imports	1.7	2.2	2.2	2.5	3.1
Total U.S.+Imports	17.8	21.6	22.7	23.9	24.5

FIGURE 6-18

Current Technology – U.S. Regional Production
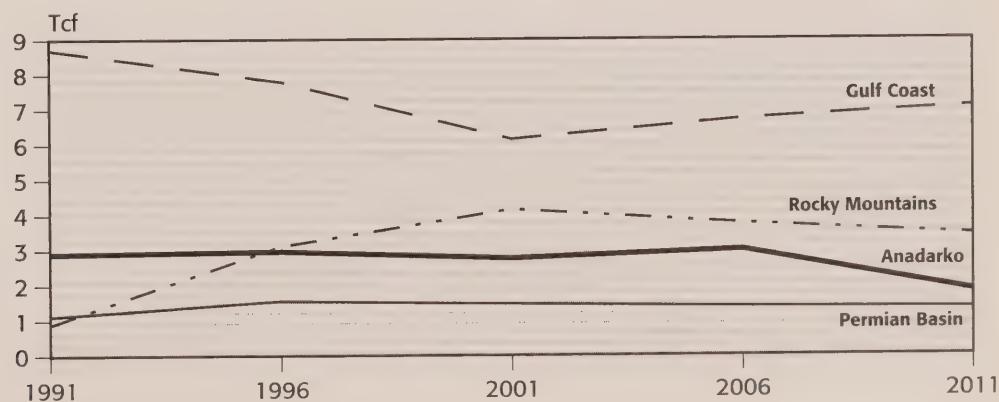
Rocky Mountain region increases to 3.1 Tcf/year in 2001, slightly less than in the Current Technology case, it then drops to 2.7 Tcf/year by 2011. Anadarko production rises to 3.8 Tcf/year by 1996, remaining at that level until 2006, gaining more market share (about 18 percent) than it would under the Current Technology assumptions. Production levels then decline to 3.1 Tcf/year by 2011. The Permian Basin also shows a larger increase in the High Technology case; its market share is expected to be six percent higher than in the Current Technology case. Since the inter-relationship of production from the various basins reflects combination of supply costs and tolls, NARG will always allocate a greater market share to the lowest cost supply source at a given point in time. This results in the switching of gas supply between competing basins as observed in the model output.

Alaskan gas does not flow to the Lower-48 in either case during the projection period. It is expected to be deferred considerably later in the High Technology case as compared to the Current Technology case, due to the availability of less costly gas in the Lower-48 under those assumptions.

The NARG results show that a small amount of backstop gas should begin to flow in 2011 using Current Technology assumptions and after 2020 using High Technology assumptions. Over the projection period, LNG imports to existing receiving terminals are projected to rise modestly from less than 0.1 to 0.3 Tcf/year by 2011 under Current Technology assumption, but are not expected to rise at all using High Technology assumptions. Coalbed methane production is expected to increase from 0.4 to about 1.6 Tcf/year by 2011 in both technology cases, indicating that it loses some market share in the High Technology case as total production volumes are higher with those assumptions, but coalbed methane production is about the same.

6.6.2.4 Canadian Exports

Figure 6-20 shows net Canadian exports for the two cases. In the Current Technology case, net exports are projected to grow to 3.4 Tcf/year between 1991 and 2006; exports are then expected to decrease to 2.8 Tcf/year by 2011. In 1991, Canadian exports accounted for just over nine percent of the total U.S. demand, they should reach almost 16 percent by 2006 before declining to about 14 percent by 2011.

In the High Technology case, exports are expected to increase to 3.1 Tcf/year, capturing some 13 percent of the U.S. market. However most of the growth occurs toward the end of the projection period. This is because more U.S. gas is expected to be available at lower prices than Canadian gas until 2006. Exports in the High Technology case do not decline towards the end of the projection since gas prices do not cause migration of demand to other fuels.

Export flows to three U.S. market regions under the Current Technology case are shown on Figure 6-21. Gas flowing to the California market should increase from 0.4 to 1.1 Tcf/year in 2011. This represents 22 percent of the California gas market in 1991 increasing to about 44 percent by 2011. There are two principal reasons for this market penetration: firstly the environmental regulations prohibiting the use of HFO in California

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FIGURE 6-19
High Technology – U.S. Regional Production

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
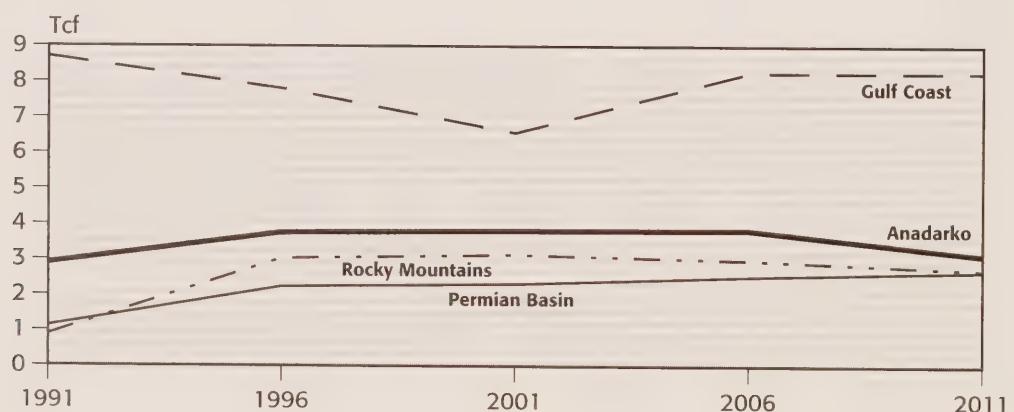
after 1996; and secondly, the assumption of rolled-in tolls on the PGT system causing that expanded system to flow at capacity. Any new pipeline connections between Alberta and California are unlikely to begin shipments before 2006.

Exports to the Central market, a combination of the East North Central and the West North Central demand regions, are expected to rise from 0.7 to 1.5 Tcf/year between 1991 and 2006 and then to drop to 1.1 Tcf/year by 2011. This would increase the market share of Canadian gas from about 13 to approximately 25 percent in 2006, declining thereafter to about 20 percent by 2011. Exports to the Northeast/Mid-Atlantic are expected to rise from 0.2 to 0.7 Tcf/year in 2006 and then to decrease to 0.6 Tcf/year in 2011. This would indicate an increase of market share from slightly over eight to about 25 percent. Exports to the Central and Northeast/Mid-

Atlantic markets are expected to fall after 2006 due to fuel switching in both the non-core industrial and electric generation sectors.

Figure 6-22 shows the major exports by market region for the High Technology case. Under these assumptions, exports to California are expected to be similar to those in the Current Technology case, also growing to 1.1 Tcf/year. Shipments on a new Alberta/California pipeline would be unlikely to begin before 2011 in this case. Exports to the Central markets are projected to reach 1.4 Tcf/year in 2011, again similar to the Current Technology case. However, the majority of the growth is projected to occur in the later years as Canadian gas becomes more competitive after 2006. The market share is projected to be about 20 percent by 2011. Exports to the Northeast/Mid-Atlantic follow a similar pattern to that in the Central region; however, the

FIGURE 6-20

Canadian Exports
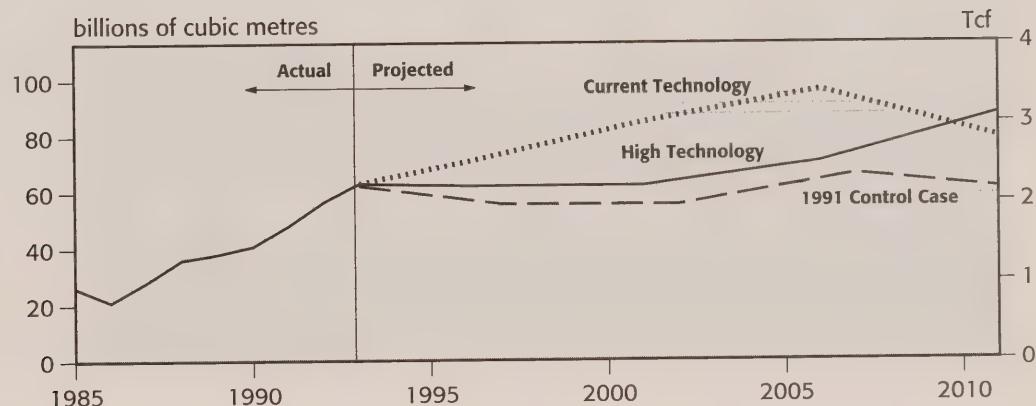
FIGURE 6-21

Current Technology – Exports to U.S. Market Regions
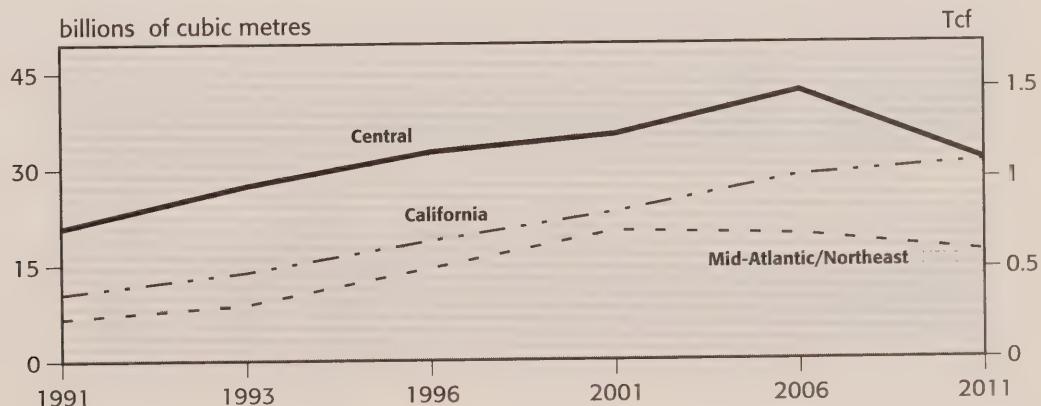
growth is projected to start a little sooner (2001) and the level of exports reaches about 0.7 Tcf/year by 2011, resulting in a 22 percent market share at that time, slightly lower than the Current Technology case.

6.6.2.5 Imports to Canada

For both technology cases, imports into Canada are projected to increase from less than 0.1 Tcf/year in 1991 to about 0.4 Tcf/year. The higher levels of imports are expected to be achieved sooner in the High Technology case, 2006 vs 2011 with Current Technology case. Current import capacity is 0.23 Tcf/year. During the consultation process, strong views were expressed that physical imports would not exceed 0.2 Tcf/year; however a higher level could be achieved through exchanges or backhaul. The NARG projection is based on an apparent economic advantage to use U.S. gas in the central Ontario market. The model does not allow producer price discounts, since these would reduce rents accruing to producers for the exploitation of the resource. Nevertheless, in this instance Canadian producers may try to maintain their market share through this method. It is the Board's view that imports to Canada are unlikely to exceed 0.2 Tcf/year on a sustained basis.

6.6.2.6 Canadian Fuel Switching

In 1991, overall demand for the industrial market was 0.8 Tcf, of which the switchable component (non-core) was 0.3 Tcf/year. 0.2 Tcf/year of this market segment was supplied by gas and 0.1 Tcf equivalent/year was supplied by oil. Under the Current Technology case, the total industrial demand is projected to remain fairly flat, with gas remaining at about 0.2 Tcf/year for

the projection due to the constraint on switching. In the electricity generation market, overall demand was 0.05 Tcf/year in 1991, with gas supplying 0.04 Tcf/year and oil supply accounting for 0.01 Tcf/year. These figures do not include any demand for gas in the Atlantic provinces. By 2011, the demand for electric generation is projected to grow to the equivalent of 0.2 Tcf/year, and is supplied equally by gas and oil.

In the non-core market, under the High Technology assumptions, gas is expected to increase its share of the market by 0.2 Tcf/year over the projection period. The requirement for oil should drop after 1991 from an initial level equivalent to 0.1 Tcf/year of natural gas. In the electricity generation market, there is very little growth in the oil share. Most of the growth in this market is projected to belong to gas, which grows to 0.5 Tcf/year in 2011.

6.6.2.7 U.S. Demand

Under the Current Technology case (Figure 6-23) total gas demand is projected to increase continuously to 21.0 Tcf/year by 2006, after which it is expected to fall to 19.4 Tcf/year by 2011, due to fuel switching.

For the High Technology case (Figure 6-24) total gas demand is projected to grow to about 22.7 Tcf/year by 2011. This is because gas prices in this case are always lower than oil prices, and hence gas gains market share in both the non-core and electric generation markets. See Figure 6-25 for burner tip prices.

Table 6-11 shows the geographic distribution of demand for both cases. Except for California, most of the growth is expected to be outside the large market areas which are typically served by Canadian gas.

FIGURE 6-22
High Technology – Exports to U.S. Market Regions

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
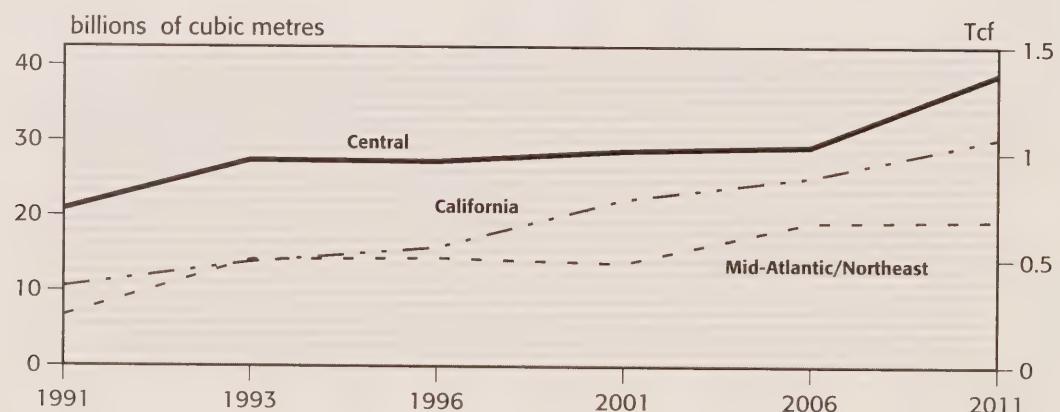
6.6.2.8 U.S. Fuel Switching

Table 6-12 shows that HFO demand under the Current Technology case is expected to rise in the non-core market from 0.2 to 1.9 Tcf equivalent/year by 2011. In the electrical generation market, HFO demand is expected to rise to about 2.3 Tcf equivalent/year. It appears that oil is taking market share away from gas, due to price.

As noted earlier, there is virtually no inter-fuel substitution in the High Technology case due to relatively low gas prices compared to oil.

Figure 6-25 illustrates U.S. non-core burner tip prices. Gas prices are projected to rise at a higher rate than oil prices after 1996. As a result, gas loses market share to oil as depicted in Figure 6-26.

Figure 6-27 shows that in the electricity generation market, the burner tip gas prices are much closer to oil until the latter part of the projection. Therefore, gas does not lose market share to oil until 2006 (Figure 6-28).

The magnitude of switchable volumes illustrated in these figures is likely overstated as there is no direct link in NARG between HFO demand and prices, oil prices being exogenous. It is unlikely that the fuel oil demands indicated, approximately 2 MMbd, could be satisfied without increased HFO prices. The amount of switching that would occur under this case is uncertain, but would likely be diminished by the higher HFO prices to probably be in the range of 1 MMbd.

FIGURE 6-23
Current Technology – U.S. Gas Demand
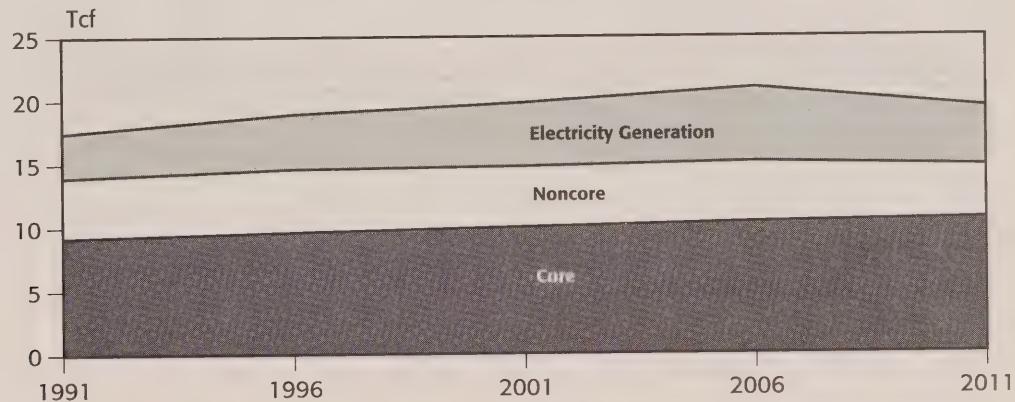
FIGURE 6-24
High Technology – U.S. Gas Demand
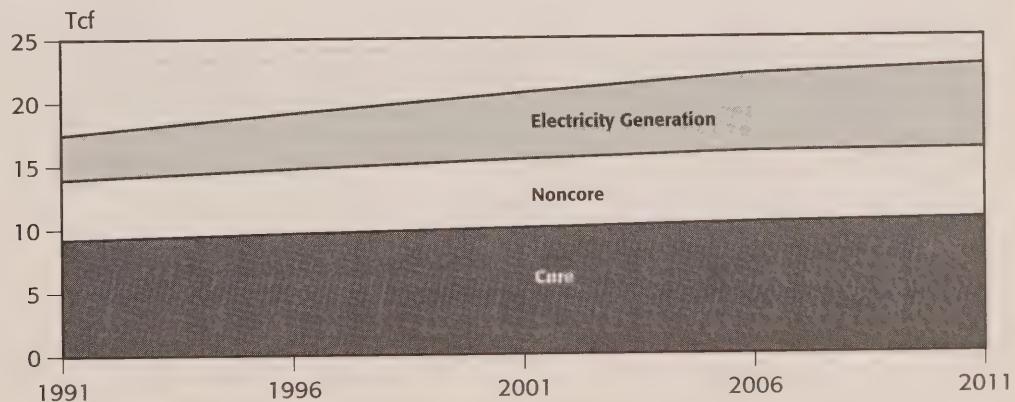
6.6.3 Comparisons With Other Projections

6.6.3.1 Organizations Surveyed

The following organizations have recently released projections which form the basis of our comparisons:

- The California Energy Commission (CEC) – 1993 Natural Gas Market Outlook.

- Energy Information Administration (EIA) – Annual Energy Outlook 1994.

- Gas Research Institute (GRI) – Long-term Trends in U.S. Gas Supply and Prices (1993).

- National Petroleum Council (NPC) – The Potential for Natural Gas in the U.S. (1992).

- Natural Resources Canada (NRCan) – Canada's Energy Outlook 1992 to 2020 (1993).

TABLE 6-11
U.S. Gas Demand By Region
Tcf/Yr

	Current Technology				
	1991	**1996**	**2001**	**2006**	**2011**
California	1.8	2.2	2.4	2.6	2.5
WSC	5.3	5.4	5.4	5.6	5.1
ENC	3.3	3.5	3.5	3.7	3.2
Mid – Atl	2.0	2.2	2.3	2.3	1.9
Other	5.1	5.6	6.2	6.8	6.7
Total	17.5	18.9	19.8	21.0	19.4
	High Technology				
California	1.8	2.2	2.4	2.6	2.6
WSC	5.3	5.4	5.5	5.7	5.8
ENC	3.3	3.5	3.7	4.0	4.0
Mid – Atl	2.0	2.2	2.4	2.4	2.5
Other	5.1	5.8	6.7	7.4	7.8
Total	17.5	19.1	20.7	22.1	22.7

TABLE 6-12
U.S. Gas And Oil Demand
Tcf/Yr

Current Technology									
	1991			**2001**			**2011**		
	Gas	HFO	LFO	Gas	HFO	LFO	Gas	HFO	LFO
Core	9.2			10.0			10.6		
Noncore	4.7	0.2		4.8	0.9		4.2	1.9	
Electricity	3.5	1.2	0.1	5.0	0.7		4.6	2.3	0.2
Total	17.5	1.4	0.1	19.8	1.6		19.4	4.2	0.2
High Technology									
Core	9.2			10.0			10.6		
Noncore	4.7	0.2		5.4	0.3		5.5	0.5	
Electricity	3.5	1.2	0.1	5.2	0.5		6.7	0.5	
Total	17.5	1.4	0.1	20.7	0.8		22.7	1.0	

FIGURE 6-25
U.S. Non-Core Burner-Tip Prices
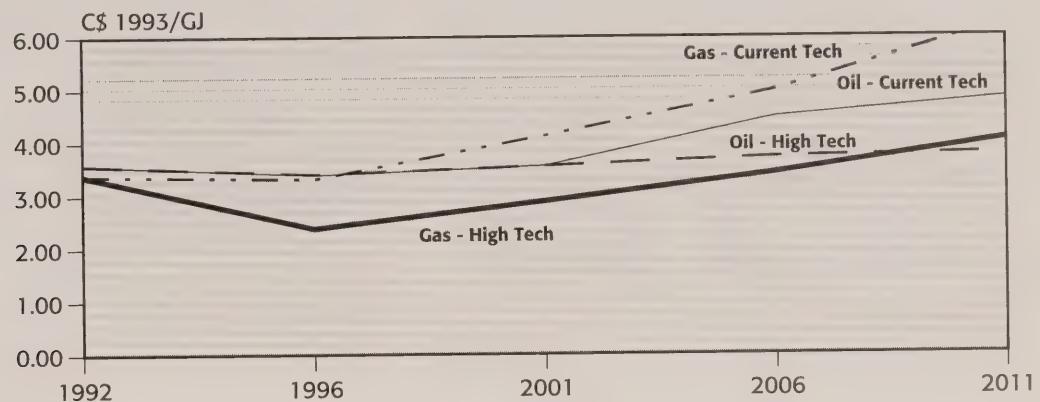
FIGURE 6-26
U.S. Non-Core Demand
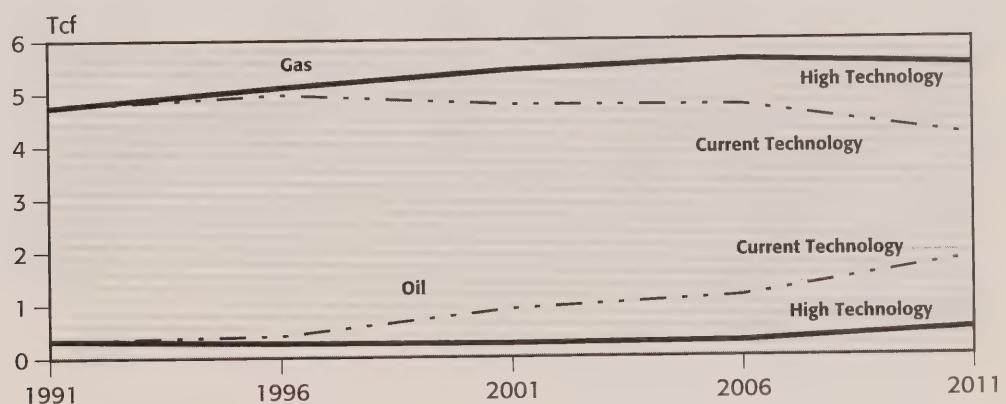
FIGURE 6-27
U.S. Fuel Prices for Electricity Generation
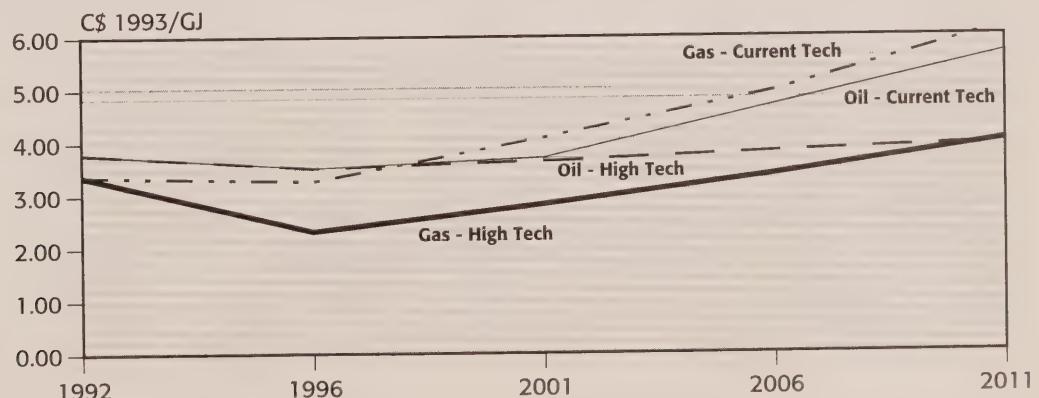
- American Gas Institute (AGA) – Gas Energy Demand and Supply Outlook 1993 to 2010 (1993).

Each organization incorporates different assumptions and modelling techniques, and therefore, arrives at different results. We have not attempted to rationalize these results as there are many variables and assumptions that are not explicit in the various reports. We have summarized, where possible, the major economic assumptions to the fundamentals underlying the analyses.

6.6.3.2 Summary of Assumptions and Results

Two of the projections did not provide macroeconomic assumptions (CEC and AGA), and three did not provide projections of Canadian production and prices (AGA, EIA and NPC). The average GDP growth rate assumed for the U.S. varied between 1.9 percent (NRCan) and 2.4 percent (NPC), with the majority being about 2.1 percent. U.S. inflation was expected to be between 3.6 percent (EIA) and 4.1 percent (GRI). Assumptions for Canadian GDP and inflation were generally not stated except for NRCan which assumed 2.5 and 2.9 percent respectively.

Table 6-13 shows the results for key indicators used in these comparisons for the six projections. In the following summary, the highest and lowest projections from the six projections for each indicator are identified as well as the two projections for the NEB cases. Some of the results have been adjusted by the Board to give consistent units of comparison.

Oil Price

In 1995, the NPC projects the lowest oil price of US (1993)$16.59 per barrel assuming their Case #2, and NRCan projects the highest price of US$22.03 per barrel. The NEB expects the price to be within this range at US$20.50 per barrel. Projections by the EIA are not available for this year.

For the year 2000, the NPC projects the lowest price of US$18.19 per barrel, again assuming Case #2. The highest projection is US$25.06 per barrel by the CEC. The NEB projects the price to be US$21.75 per barrel.

By 2010, the NPC again projects the lowest price of US$21.40 per barrel, whereas, the CEC projects the highest price of US$31.73 per barrel. The NEB is closer to the low end of the range at US$23.00 per barrel.

Alberta Fieldgate Price

The Alberta fieldgate gas prices in 1995 range from a low of $1.55 per gigajoule by NRCan to a high of $1.81 per gigajoule by the CEC. The NEB price is $1.56 per gigajoule for the Current Technology Case; however, the price for the High Technology Case is lower than the lowest projection (NRCan) by $0.02 at $1.53 per gigajoule.

In 2000, the range is from $2.00 by NRCan to $2.29 per gigajoule by GRI. The NEB expects the price to be $2.18 for the Current Technology Case, and $1.35 per gigajoule for the High Technology Case. The latter is lower than the bottom end of the range by $0.65 per gigajoule.

FIGURE 6-28

U.S. Electricity Generation Demand
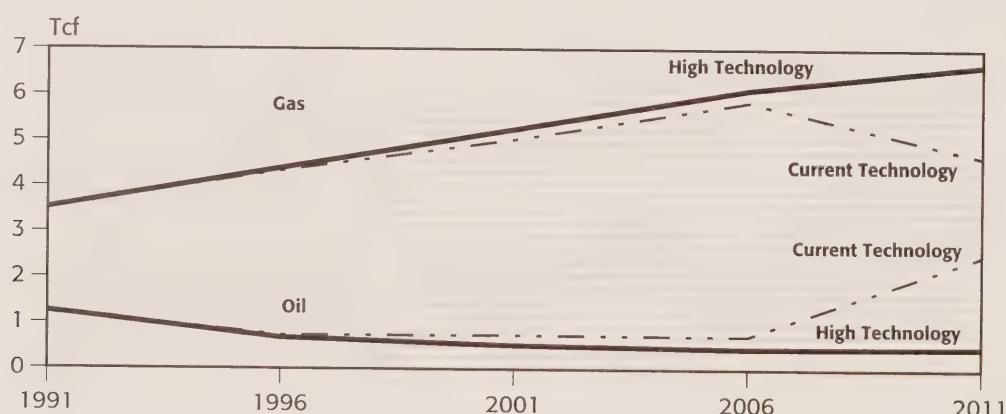
In 2010, the lowest projection is $2.50 per gigajoule (NRCan) and the highest is $3.37 per gigajoule (CEC). The projection for the NEB's Current Technology Case is $4.21 per gigajoule, which is higher than the CEC by $0.84. The price for the High Technology Case is $2.26 per gigajoule, which is lower than NRCan's by $0.24.

Canadian Production

In 1995, the CEC expects production levels of 4.5 Tcf/year, while GRI expects the highest levels of 4.9 Tcf/year. The NEB expects slightly higher levels of 5.0 Tcf/year assuming Current Technology, while within the range at 4.8 Tcf/year assuming High Technology.

By 2000, the GRI projection the lowest level at 4.9 Tcf/year, and the highest projection of 5.5 Tcf/year is by the CEC. The NEB projection for the Current Technology Case is higher than CEC's by 0.4 Tcf/year. A level of 5.1 Tcf/year is expected for the High Technology Case.

For the year 2010, the lowest projections are from GRI and NRCan at 5.7 Tcf/year, and the CEC expects

TABLE 6-13
Table of Comparisons

	Alta Fieldgate Price C$ 1993/GJ	Canadian Production Tcf/Yr	Lower-48 Production Tcf/Yr	Canadian Exports Tcf/Yr	World Oil Price 1993 US$/bbl
1995					
NEB					
Current Tech	1.56	5.0	17.8	2.4	20.50
High Tech	1.53	4.8	18.4	2.2	20.50
AGA			19.7	2.3	
CEC	1.81	4.5	17.2	2.0	21.49
EIA					
GRI	1.65	4.9	17.5	2.3	19.99
NPC – Case #1			17.9	2.5 *	20.34
NPC – Case #2			17.2	2.5 *	16.59
NRCAN	1.55	4.8	18.3	2.7	22.03
2000					
NEB					
Current Tech	2.18	5.9	18.1	2.9	21.75
High Tech	1.35	5.1	20.1	2.2	21.75
AGA			19.6	2.6	
CEC	2.19	5.5	17.7	2.6	25.06
EIA			18.4	2.7	21.13
GRI	2.29	4.9	18.8	2.7	21.69
NPC – Case #1			18.6	3.1 *	22.58
NPC – Case #2			16.4	2.7 *	18.19
NRCAN	2.00	5.4	18.1	2.8	24.15
2010					
NEB					
Current Tech	4.21	5.9	17.8	2.9	23.00
High Tech	2.26	6.8	21.0	3.0	23.00
AGA			21.7	2.7	
CEC	3.37	6.0	21.3	2.7	31.73
EIA			19.7	2.9	28.72
GRI	3.17	5.7	21.1	3.2	27.88
NPC – Case #1			20.7	3.6 *	29.80
NPC – Case #2			17.7	3.1 *	21.40
NRCAN	2.50	5.7			25.18

*Includes Canadian and LNG exports

the highest production at 6.0 Tcf/year. The NEB's projection for the Current Technology Case is lower than CEC's at 5.9 Tcf/year. However, levels of 6.8 Tcf/year are expected assuming High Technology.

Lower-48 Production

In 1995, Lower-48 production levels range from 17.2 Tcf/year by the NPC and CEC to 19.7 Tcf/year by AGA. For the Current and High Technology Cases, the NEB expects levels of 17.8 and 18.4 Tcf/year respectively.

In 2000, the NPC projects the lowest level of 16.4 Tcf/year, and AGA expects the highest level of 19.6 Tcf/year. The NEB projection for the High Technology Case is higher than AGA's by 0.5 Tcf at 20.1 Tcf/year. The projection for the Current Technology Case falls within the range at 18.1 Tcf/year.

By 2010, the range is from 17.7 to 21.7 Tcf/year, by the NPC and AGA respectively. The NEB projections for both cases are within this range at 17.8 and 21.0 Tcf/year.

Canadian Exports

Export projections for 1995 range from 2.0 Tcf/year by the CEC to 2.7 Tcf/year by NRCan. The NEB expects export volumes of 2.4 Tcf/year assuming Current Technology and 2.2 Tcf/year assuming High Technology.

The CEC expects the lowest export volume of 2.6 Tcf/year by 2000. The highest is projected by NPC at 3.1 Tcf/year; however, this number may include small quantities (about 0.1 Tcf/year) of LNG imports to the U.S. The NEB projects levels of 2.9 Tcf/year for the Current Technology Case, while the level for the High Technology Case remains at 2.2 Tcf/year.

By 2010, the export projections range from 2.7 Tcf/year by the CEC to 3.6 Tcf/year by the NPC. Again, the NPC projections may include LNG imports. The NEB projections are within this range at 2.9 and 3.0 Tcf/year for the Current and High Technology cases respectively. Projections by NRCan are not available for this year.

6.6.3.3 Summary

The NEB oil price projection tends to be in the middle to low end of the range projections by others.

The fieldgate prices projected by the NEB under the High Technology case are consistently lower than the other projections, most likely due to our aggressive assumption on supply cost. The Current Technology fieldgate price is generally within the range of the other projections except that by 2010 the NEB projection is the highest.

Regarding Canadian production the NEB's Current Technology case tends to be higher than other projections until 2010 when it is towards the lower end of the range. The High Technology case production stays within the range until 2010 when it is then the highest projection likely due to the relatively low rate of fieldgate price escalation.

The NEB's Lower-48 production projections are all within the overall range except for 2000 when the High Technology case is the highest.

NEB's projections of Canadian exports to the U.S. fall within the range projection by others for both technology cases.

NRCan has the lowest Canadian fieldgate price projection and curiously tends to be at the low end of Canadian production projections. CEC tended to be at the higher end for both fieldgate price and production of Canadian gas.

NPC appears to be the most pessimistic concerning U.S. production, consistently providing the lowest projection. AGA is consistently at the upper end of this range.

Overall, the NEB's cases appear to be generally inside the range of the projections developed by others. The results are neither consistently at the high or low-end of the ranges, except for fieldgate prices under the High Technology case. This would generally support the premise that the analyses presented provide a plausible range of outcomes, which was the primary objective of this chapter.

6.7   SENSITIVITIES

6.7.1   Introduction

The sensitivity cases were undertaken to review the effects on prices, production and exports of two significant uncertainties regarding assumptions for demand and supply.

(1)   **High U.S. Electrical Demand.** There are some optimistic views concerning the accelerated growth of the use of gas for electrical generation in the U.S. In order to reflect this, a sensitivity case has been developed that increases gas demand from 7 Tcf to 10 Tcf per year by 2006 in the electrical generation market sector. This is based on projections by GRI, the North American Electric Reliability Council and National Economic Research Associates. Most of this increased demand is expected to be for cogeneration facilities, therefore 80 percent of the additional gas demand (about 2.4 Tcf) was assumed

to be switchable from gas to LFO, the remaining 20 percent is switchable to HFO. This sensitivity is applied to both technology cases.

(2) **New Gas Supply Source**. Over the duration of the projection period it is likely that new sources of gas will be developed. For example, there is evidence of possibly significant resources in the sub-salt plays in the U.S. Gulf of Mexico. It is also possible that Mexico may become a significant exporter of natural gas. In order for these new supplies to be competitive with producing basins their supply costs must be comparable or lower than existing supply regions. In this sensitivity case, which applies to both technology cases, a new supply region with 70 Tcf of gas and supply costs about equal to the Gulf Coast Offshore has been added to the modelling network in 2000.

The following section discusses these two sensitivity cases for both technology cases. Throughout this section each sensitivity case is compared to its corresponding base case. For example, the results of Sensitivity Case 1 using the Current Technology assumptions is compared only to those for the original Current Technology case from Section 6.6.2.

The original case, either Current Technology or High Technology, will be referred to as the "base" in the text. The main points of comparison will be fieldgate price, Canadian production, exports to the U.S., U.S. production and fuel switching.

6.7.2 Sensitivity Case 1: High U.S. Electrical Demand

Figure 6-29 compares the assumed U.S. gas demand for electrical generation for both the Current and High Technology sensitivity cases and the two base cases. Under Current Technology, demand is projected to rise steadily to about 8 Tcf/year in 2001, 3 Tcf/year more than the base case, after which gas is expected to lose market share to oil. Consequently the incremental demand is only about 1 Tcf/year by 2011. Under High Technology, demand is projected to increase in the same manner; but no market share is lost, and the increased demand is projected to remain at 3 Tcf/year until 2011. At that time, total demand is projected to approach 10 Tcf/year for this sector.

6.7.2.1 Comparison to Current Technology Base Case

Figures 6-30 to 6-33 display the results of this sensitivity compared to those of the base Current Technology case. The main observations are as follows:

- Alberta fieldgate prices grow at eight percent per year to about $5.00 per gigajoule by 2011 and are about $0.65 higher than the base at that time.

- Average U.S. fieldgate prices reach $6.00 per gigajoule by 2011, a growth of almost six percent per year.

- Total Canadian production reaches 7.5 Tcf/year in 2006, before declining to 5.2 Tcf by 2011.

- Alberta production peaks in 2001 at 5.6 Tcf and then declines over the rest of the projection period to 3.2 Tcf/year by 2011.

- B.C. production rises through the projection period to 1.8 Tcf/year by 2011.

- East Coast gas comes on stream in 2006; there is no Northern production in the projection.

- U.S. production peaks at 20.8 Tcf/year in 2001 and then declines to 17.6 Tcf by 2011.

- Canadian exports rise after 1996 and peak at 4.3 Tcf/year in 2006. They decline to 2.4 Tcf by 2011.

6.7.2.2 Comparison to High Technology Base Case

Figures 6-34 to 6-36 display the results of this sensitivity compared to those of the base High Technology case. The main observations are as follows:

- Alberta fieldgate prices grow at three and a half percent per year to about $2.50 per gigajoule by 2011 and are about $0.15 higher than the base at that time.

- Average U.S. fieldgate prices reach $3.50 per gigajoule by 2011, a growth of two and a half percent per year.

- Total Canadian production reaches 8.0 Tcf/year by 2011.

- Alberta production rises continuously through the projection to about 6.7 Tcf/year by 2011.

- B.C. production peaks in 2001 at 1.4 Tcf/year before declining to about 1 Tcf/year by 2011.

- There is no Northern or East Coast gas production in the projection.

- U.S. production rises to 22.0 Tcf/year by 2011.

- Canadian exports rise after 1996 to 3.7 Tcf/year by 2011.

6.7.2.3 Discussion: Sensitivity Case 1 – High U.S. Demand

In comparison to the base case, the fieldgate prices in the Current Technology sensitivity are 15 percent higher in Alberta and 11 percent higher in the Lower-48. Increases are somewhat smaller in the High Technology sensitivity, being eight and seven percent respectively for Alberta and the U.S.

During the last five years of the Current Technology projection, the growth rate for both Alberta and U.S. fieldgate prices is reduced, since oil is providing a ceiling to gas prices in the non-core and electrical generation sectors.

Using the Current Technology assumptions with the High Demand sensitivity case, it is apparent that the additional gas demand of about 3 Tcf/year taxes the production capabilities of both Canada and the U.S. to satisfy the demand after 2006 leading to higher gas prices. This is indicated by lower Canadian production and about equal U.S. production in 2011, despite the demand increase. In this case more fuel switching occurs in response to higher gas prices.

In the High Technology sensitivity, no supply problem is apparent as both the U.S. and Canada appear to be able to increase production to the required level. Further, the increase in fieldgate price in both countries is relatively modest. However, supply may be near its limit at competitive prices after 2011, as fuel substitution becomes significant.

The high level of Alberta production in the High Technology sensitivity relative to B.C., is a function of the supply cost curves for each province. It is a similar

FIGURE 6-29
Sensitivity Case 1 – U.S. Electrical Gas Demand
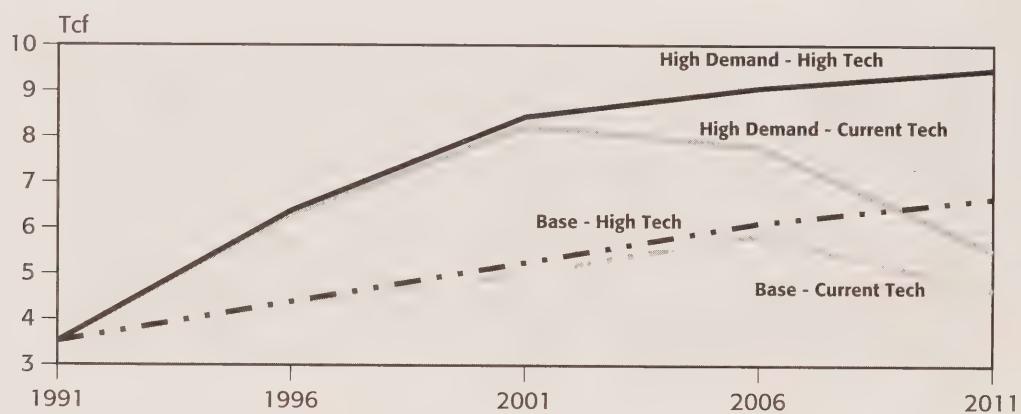
FIGURE 6-30
Sensitivity Case 1 – Alberta Fieldgate Prices

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
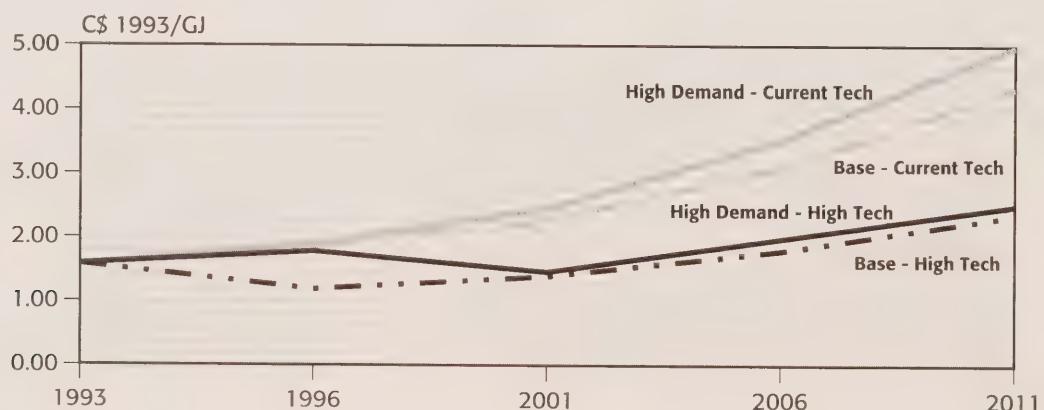
FIGURE 6-31
Sensitivity Case 1 – Current Technology – Canadian Production
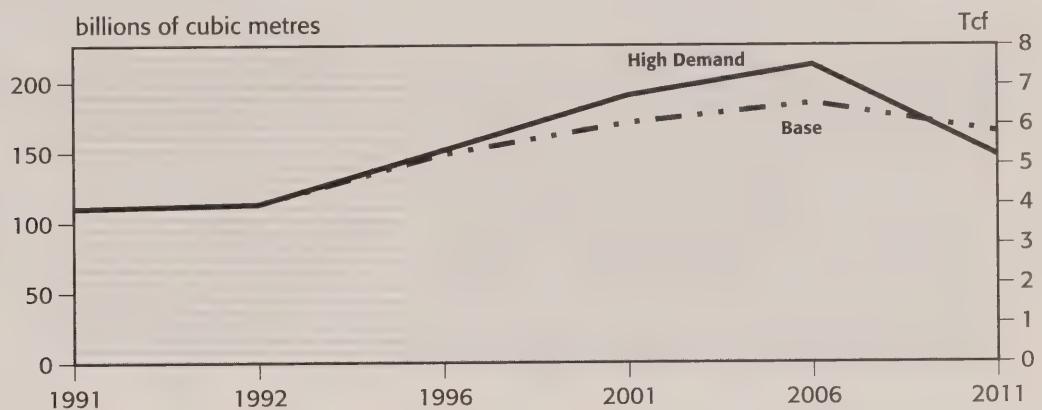
FIGURE 6-32
Sensitivity Case 1 – Current Technology – Provincial Production
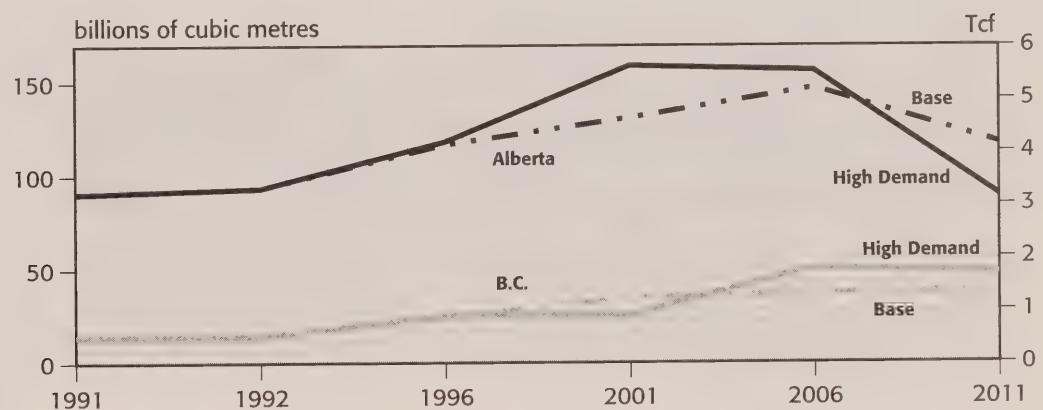
FIGURE 6-33
Sensitivity Case 1 – Current Technology – Canadian Exports
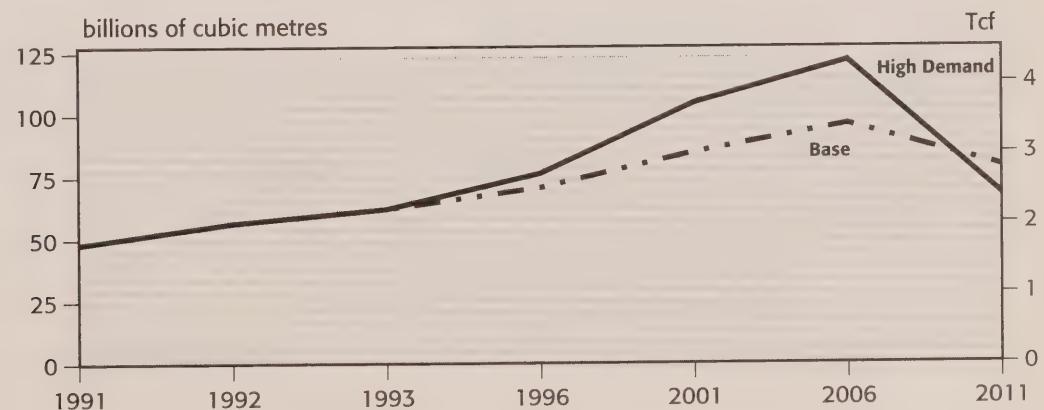
FIGURE 6-34
Sensitivity Case 1 – High Technology – Canadian Production

billions of cubic metres / Tcf

High Demand

Base

1991 1992 1996 2001 2006 2011
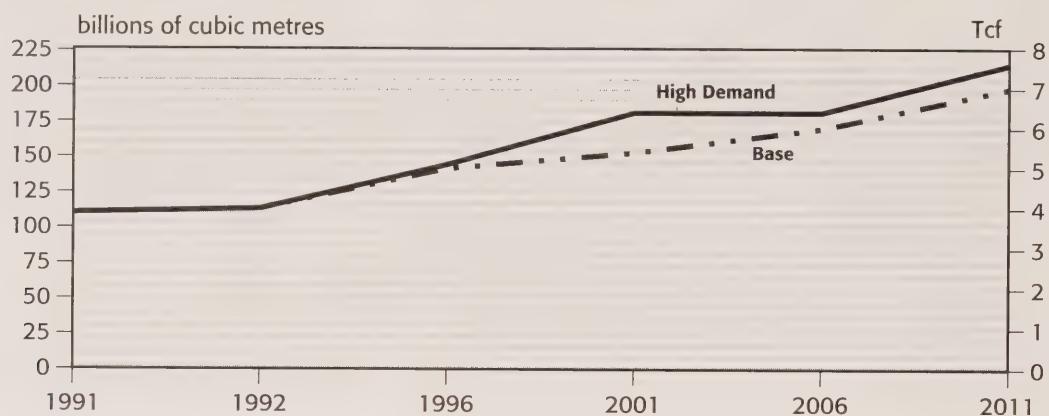
FIGURE 6-35
Sensitivity Case 1 – High Technology – Provincial Production

billions of cubic metres / Tcf

High Demand

Alberta

Base

B.C.

Base

High Demand

1991 1992 1996 2001 2006 2011
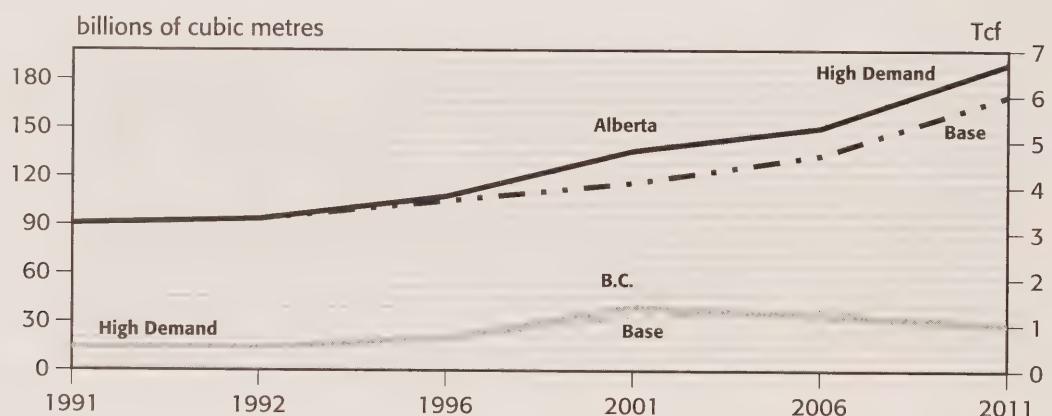
FIGURE 6-36
Sensitivity Case 1 – High Technology – Canadian Exports

billions of cubic metres / Tcf

High Demand

Base

1991 1992 1993 1996 2001 2006 2011
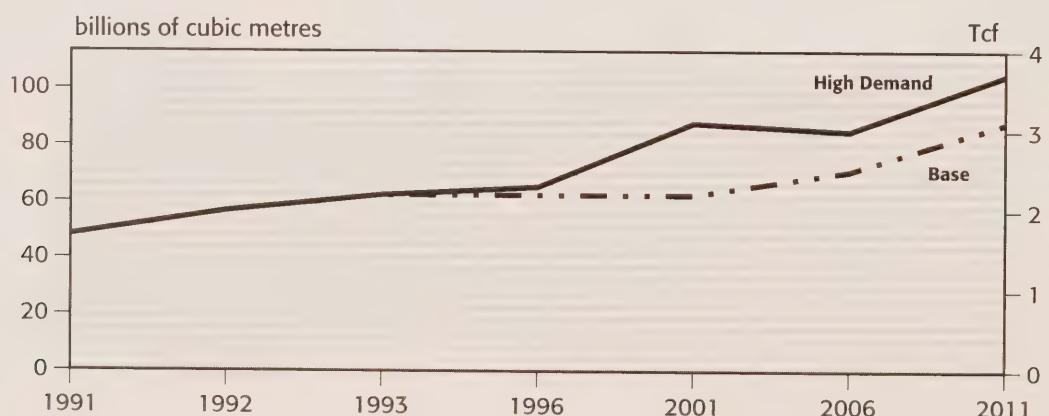
phenomenon to the comparison between Canada and the U.S. in Current and High Technology base cases, i.e., there are more remaining established gas reserves in Alberta influenced by technology than in B.C (56 Tcf vs 8 Tcf). Alberta gas, being lower cost, would therefore flow in preference to B.C. gas.

In both cases, these results suggest that export capacity expansion would be required on intra-provincial pipeline systems, particularly to transport B.C. gas to the east, as well as services to the Central U.S. and California regions. In the Current Technology case, this capacity may only be used for a short period of time – seven to ten years. In reality, it is unlikely that capacity would be constructed for such short terms. It is more probable that exports would be temporarily constrained by pipeline capacity at some level below 4 Tcf/year. Alternatively, it is possible that, having built the capacity and acquired these markets, Canadian producers would respond to market forces to maintain them, through price or transportation discounting.

6.7.3 Sensitivity Case 2: New Low Cost Gas Supply

To test the effects of larger than projection gas supplies, we assumed a new gas supply source located in the Gulf of Mexico region. We also assumed that this source would have a total resource of 70 Tcf, of which about 25 Tcf would be "remaining established reserves". This gas was assumed to become available by 2000, hence the 1996 production figures are unaffected in both cases. The source of this new gas is not specifically identified, it could be a concerted effort by Mexico to penetrate the U.S. market or it could be a new play type, such as the sub-salt play that is emerging in the offshore

Gulf. The supply cost curve for this source would be about the same as that used for the offshore Gulf of Mexico.

The comparison of U.S. production levels is shown on Figure 6-37. For the Current Technology, this sensitivity case shows that incremental levels are about 0.6 Tcf higher for 2001 and 2006; by 2011, they are higher by about 1.3 Tcf/year. This is due to the fall in production in the base case rather than a rise in production in this sensitivity case.

In the High Technology case, the production increment is about 0.8 Tcf/year in 2001, rising to about 1 Tcf/year by the end of the projection.

6.7.3.1 Highlights of Results compared to Current Technology Base Case

Figures 6-38 to 6-41 display the results of this sensitivity compared to those of the base Current Technology scenario. The main observations are as follows:

- Alberta fieldgate prices grow at five and a half percent per year to about $4.10 per gigajoule by 2011 and are about $0.25 lower than the base at that time.

- Average U.S. fieldgate prices reach $5.05 per gigajoule by 2011, about $0.45 per gigajoule less than the base scenario and a growth of almost four percent per year.

- Total Canadian production reaches 6.1 Tcf/year in 2006, before declining to 5.8 Tcf by 2011.

- Alberta production peaks in 2006 at 5.4 Tcf and then erodes to 4.2 Tcf/year by 2011.

FIGURE 6-37
Sensitivity Case 2 – U.S. Production
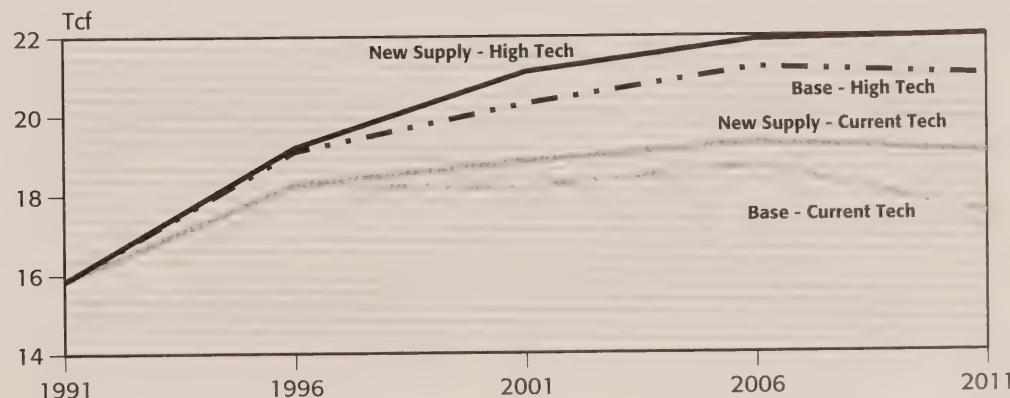
FIGURE 6-38

Sensitivity Case 2 – Alberta Fieldgate Prices

C$ 1993/GJ

5.00	
4.00	Base - Current Tech
3.00	New Supply - Current Tech
2.00	Base - High Tech
1.00	New Supply - High Tech
0.00	

1993   1996   2001   2006   2011
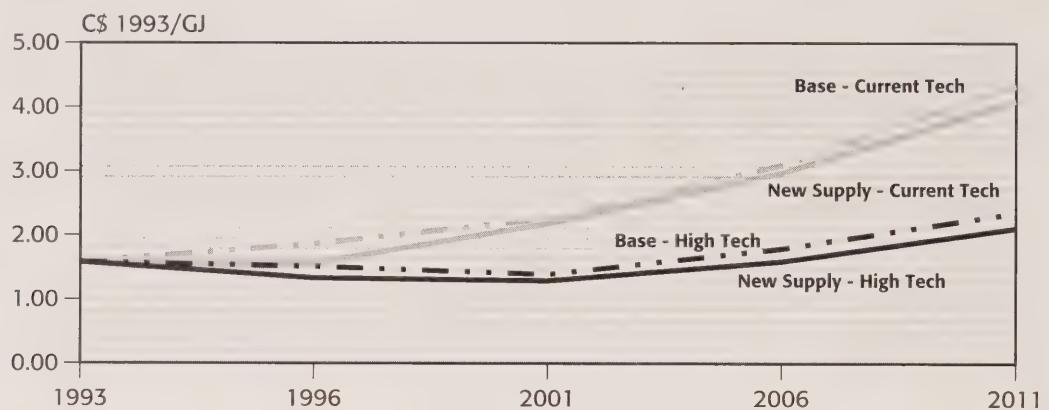
FIGURE 6-39

Sensitivity Case 2 – Current Technology – Canadian Production

billions of cubic metres   Tcf

180	Base / 7
150	New Supply / 6
120	5 / 4
90	3
60	2
30	1
0	0

1991   1992   1996   2001   2006   2011
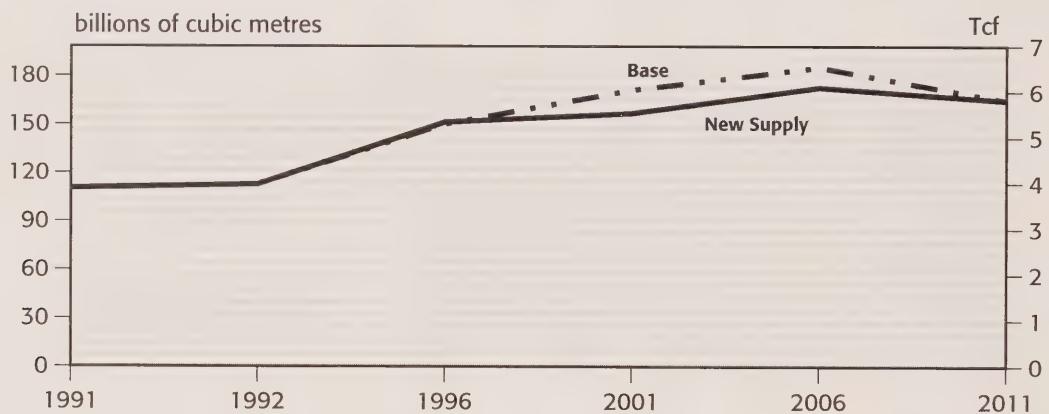
FIGURE 6-40

Sensitivity Case 2 – Current Technology – Provincial Production

billions of cubic metres   Tcf

150	Alberta / New Supply / 6 / 5
100	Base / 4 / 3
50	B.C. / Base / 2 / 1
0	New Supply / 0

1991   1992   1996   2001   2006   2011
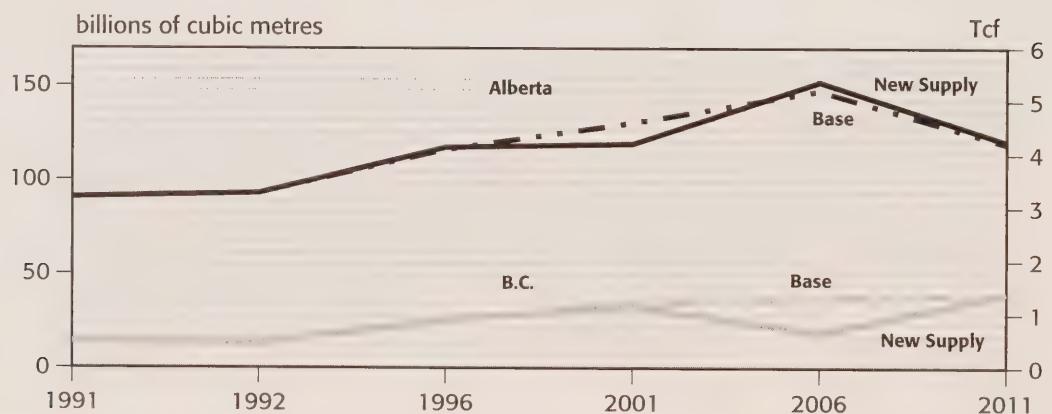
- B.C. production rises to 1.1 Tcf/year by 2001, declines and then recovers to 1.1 Tcf/year by 2011.

- East Coast gas does not come on stream until after 2011; there is no Northern production in the projection.

- Canadian exports peak at about 2.9 Tcf/year in 2006, 0.5 Tcf less than the base scenario and then decline to 2.8 Tcf by 2011.

6.7.3.2 *Highlights of Results compared to High Technology Base Case*

Figures 6-42 to 6-44 display the results of this sensitivity compared to those of the base High Technology scenario. The main observations are as follows:

- Alberta fieldgate prices grow at less than two percent per year to about $2.10 per gigajoule by 2011 and are about $0.25 lower than the base at that time.

- Average U.S. fieldgate prices reach $3.00 per gigajoule by 2011, about $0.30 per gigajoule less than the base scenario and a growth of less than two percent per year.

- Total Canadian production remains flat at about 4 Tcf annually until 2001. Thereafter, it rises to about 6.8 Tcf/year by 2011.

- Alberta production is about 0.8 Tcf/year less than the base scenario in 2001. While the production tracks the base case, it remains about 0.8 Tcf/year less to the end of the projection.

- B.C. production drops about 0.4 Tcf/year by 2001 and then recovers to about 1.0 Tcf/year by 2011.

- There is no East Coast or Northern production in the projection.

- Canadian exports decline to about 1.4 Tcf/year by 2001, 0.8 Tcf less than the base case and then recover to about 2.4 Tcf by 2011, but still 0.7 Tcf/year lower than the base.

6.7.3.3 *Discussion: Sensitivity Case 2 – New Low Cost Gas Supply*

If significant low cost, incremental gas volumes become available, then as expected, there would be reduction in Canadian prices, production and exports in the medium term as the new supply source is displacing Canadian exports. This would make available lower cost Canadian gas for domestic use, thus reducing prices. It occurs to about the same extent on both the Current and High Technology cases. As the new supply becomes more costly, there is an indication that Canadian production would recover in the Current Technology case, but not in the High Technology case. Prices appear to remain lower in both cases.

In both cases this sensitivity indicates that exports are reduced during in the period 2001 to 2006. The High Technology case shows a higher reduction of about 0.7 Tcf/year (vs 0.5 Tcf in Current Technology) and this difference persists to the end of the projection. In the Current Technology case exports recover to the base level by 2011.

This sensitivity case has a substantial effect on U.S. fuel switching reducing the amount to 2.9 Tcf

FIGURE 6-41

Sensitivity Case 2 – Current Technology – Canadian Exports
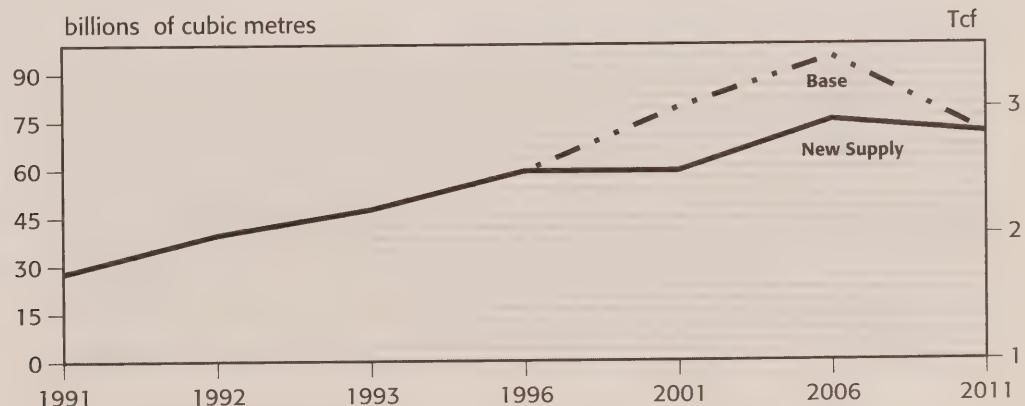
FIGURE 6-42

Sensitivity Case 2 – High Technology – Canadian Production
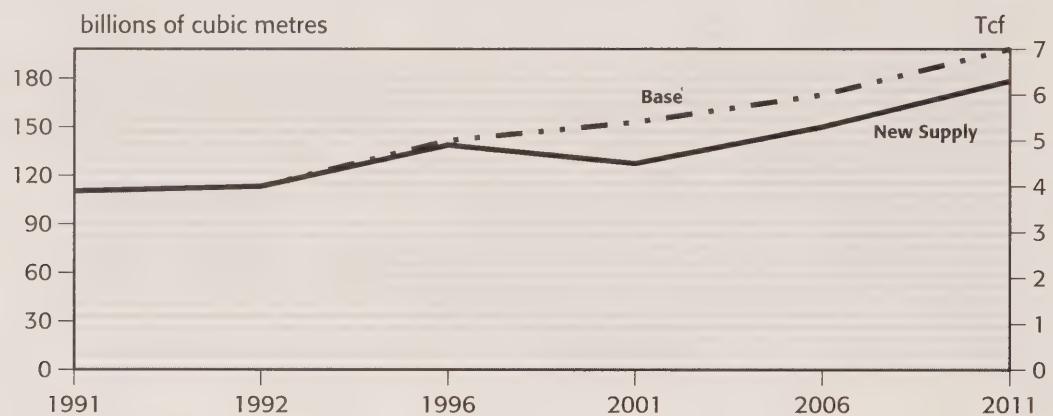

FIGURE 6-43

**Sensitivity Case 2 – High Technology – Provincial Production**
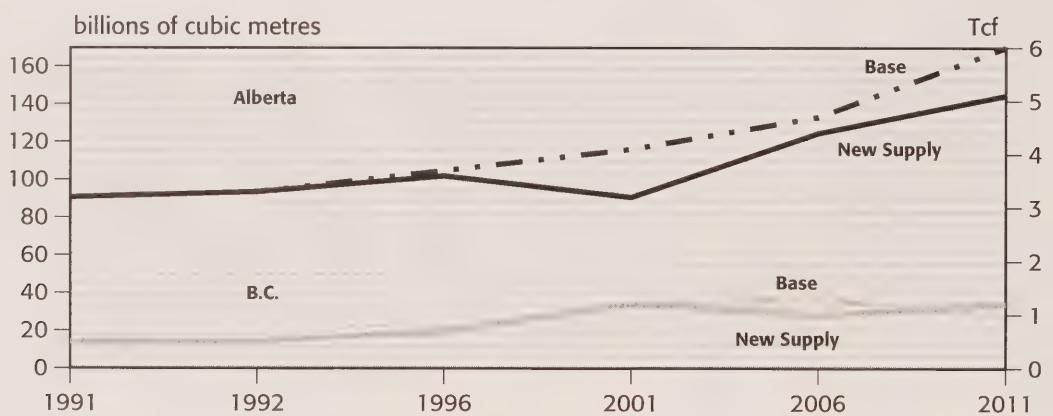
FIGURE 6-44

Sensitivity Case 2 – High Technology – Canadian Exports
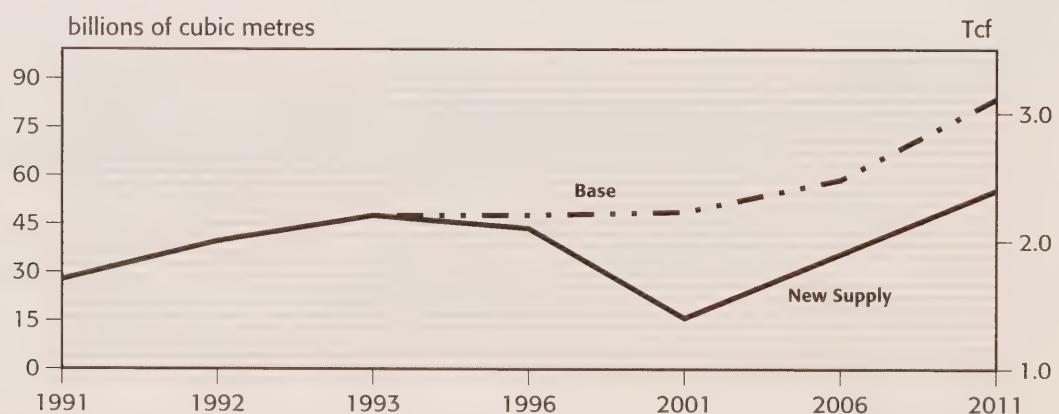
equivalent by 2011, vs 4.2 Tcf equivalent in the base case. This would mean that about 1.3 MMbd of HFO would be required to supply this sector. This is still relatively high compared to the 1991 level of 0.8 MMbd, but should be attainable with the premia included in the HFO price.

6.8 PRODUCTIVE CAPACITY OF CANADIAN NATURAL GAS

6.8.1 Approach

Given the overall demand projections described in the previous sections, we make projections of productive capacity from established reserves and reserves additions in the WCSB, and frontier projects on the basis of projected gas prices and supply costs.

We begin with a description of the modelling framework used to project peak day productive capacity from established reserves and a description of how these daily projections are converted to annual projections. We follow this with a general description of how reserves additions in the WCSB are calculated and how these additions were assigned to each of the three major producing regions.

The results of the analysis for each component of supply (Table 6-14) are discussed by region. These results are then summarized for each major producing region as well as for all of Canada. We then compare our estimates of productive capacity to anticipated demand for Canadian natural gas. We also compare the total projections of productive capacity to the Control Case in the 1991 Supply/Demand Report.

Finally, we discuss the implications for future drilling activity implied by the reserves additions projections by region for each case.

Throughout this section, the results for key components of the supply projection under the Current Technology Case are compared with those under the High Technology Case.

6.8.2 Modelling Framework

The Board's methodology involves an assessment of future productive capacity for four basic components of supply. These four components are summarized in Table 6-14.

The major element of supply from **Producing Pools** is our projection of productive capacity from connected non-associated gas pools. These projections of productive capacity are derived using a modelling framework which takes account of each pool's deliverability characteristics, basic reservoir parameters and daily contract rate. Field development is built into our projections and represents the additional productive capacity achievable by connecting other existing wells within the pools, by drilling infill wells, and/or by adding compression, all assuming adequate returns to the producer. This approach incorporates drilling and compression cost data and projected producer netbacks to assess the economics of adding infill wells and/or field compression to maintain productive capacity at or near the established contract rate.

TABLE 6-14
Components of Productive Capacity

Productive Capacity Component	Description
Producing Pools	The productive capacity from connected producing pools as of 31 December 1992.
Non-producing Pools	The productive capacity estimated to become available from currently non-producing pools.
Reserves Additions	The productive capacity estimated to become available from reserves additions (revisions and extensions plus new discoveries).
Frontier	The productive capacity anticipated to be available from established reserves in frontier regions.

The modelling framework predicts peak day productive capacity for each pool modelled, at or near the assigned contract rate or a specified rate of take[25]. Rates of take for non-associated gas pools were estimated based upon specific information acquired for each of the producing regions. Our analysis was conducted using reserves estimates as of 31 December 1992. With 1993 as the first projection year, we were able to calibrate the overall results of the analysis to the actual peak production rates over the winter of 1992/1993.

Our projections of productive capacity for connected producing pools in both Alberta and B.C. show increases in capacity in 1994 over 1993 with declining rates thereafter. This increase is because we did not allow our projection model to add any infill wells or compression in 1993 – the year we used to calibrate our results.

Where appropriate, projections of productive capacity for solution gas, associated gas and gas produced from major gas cycling schemes are added to the projection for non-associated gas to make up the total projection of productive capacity from connected producing pools.

Productive capacity from currently **Non-producing Pools** is the second component addressed in this report. The modelling framework described above is used to establish a productive capacity profile for non-producing reserves by region. Connection rates for non-producing reserves are also developed for each region.

The next major component is the projection of productive capacity from **Reserves Additions**. As productive capacity from established reserves declines over the projection period, it will become increasingly necessary to add productive capacity from new reserves in the WCSB to meet the increasing levels of domestic and export demand. Our projection of reserves additions is based on the natural gas price path and direct costs of development for the WCSB described earlier in this chapter. Reserves additions are projected so that productive capacity is maintained over the longer term at a level about 10 percent higher than average annual production, or demand. This assumption ensures that peak day demand can be met.

The deliverability profile for **future reserves additions** is based on deliverability from established reserves in the producing regions of the WCSB. Annual levels of reserves additions and connection rates for those additions are derived for both the Current Technology and the High Technology cases. The connection rates for each case are shown in Appendix

Table A6-7. The gas-directed exploratory drilling activity required to achieve these levels of reserves additions is then estimated using a regression function taking into account historical data and the Board's current estimate of ultimate potential gas resources.

The final component of productive capacity is natural gas expected to become available from **Frontier** sources during the projection period. Timing depends on gas prices and the supply and transportation costs for specific frontier resources.

The projection of peak day productive capacity derived for non-associated gas pools represents what is characterized as a **non-coincidental peak day** projection of productive capacity. It represents the sum of productive capacities for all non-associated gas pools assuming they were all able to produce simultaneously. However, one cannot expect all of the gas supply to be available simultaneously due to a number of factors, such as the reliability of gas plant and field facilities. For example, NOVA has found that during extended cold periods it can rely on approximately 87 percent of the non-coincidental peak day supply to be available on a given day. The Board's productive capacity projections for non-associated gas pools are therefore reduced by a factor appropriate for each producing region to obtain an estimate of **available peak day** productive capacity (i.e., that supply of gas that is expected to be consistently available to meet peak day delivery requirements). Our estimates of productive capacity for associated and solution gas, shallow gas and gas in cycling pools are assumed to be available for peak day demand. Available annual productive capacity for each producing region is simply the available peak day times 365.

This concept is illustrated schematically in Figure 6-45. Note that the average day deliveries (i.e., annual production/365), do not include deliveries from gas storage and are less than the available peak day productive capacity. The difference between average and available peak day productive capacity, together with sufficient peak day productive capacity from gas storage, ensures that both peak day and annual requirements will be met.

Under the High Technology case, it was necessary to estimate the impact of unknown new technology on productive capacity. This was accomplished by assuming that High Technology drilling costs would be

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25 Rate of take refers to the initial rate at which gas will be produced from an entity such as a well, pool, field or area. It is usually expressed as a ratio. For example, a rate of take of 1:7 000 means that 1 unit of production on a daily basis is obtained for each 7 000 units of reserves for the entity under consideration.

75 percent of those assumed in the Current Technology Case. This represents a two percent cost decline over about 12 years. This had a modest impact on the overall results because the maximum drilling density (i.e., the maximum number of wells allowed per section) remained the same in both cases.

There are a number of uncertainties inherent in our projections of productive capacity:

- productive capacity is not easily measured, and even the historical level of productive capacity is an estimate;

- the model projections are dependent on current estimates of remaining established reserves, which are subject to change over time as pools are developed and as production data more precisely defines established reserves;

- future trends in contractual practices and specific rates of take may change over time;

- reliable technical data needed to assess the deliverability of each well is often not available for non-producing reserves and, in some cases, is not even available for producing reserves;

- the viability of some of the unconnected reserves is questionable due to poor reservoir quality, the distance of the pool from pipelines and laterals, and uncertain reserves estimates;

- while generalized assumptions about the industry's ability to connect new reserves can be made based on observation of recent trends, there is considerable uncertainty in predicting the level of new reserves to be connected over time; and

- reserves additions depend on the level of future drilling activity which is unknown and must be projected.

The analytical results which follow should not be considered as forecasts; rather they represent outcomes based on assumptions made for various cases.

These results are highly dependant upon the demand for Canadian gas in the U.S. Annual exports represent not much more than 10 percent of annual U.S. consumption, and therefore, small variations in either U.S. consumption or production can result in large variations in the demand for Canadian gas.

While projections of productive capacity from producing established reserves are based on known characteristics of the reservoirs, the outlook for productive capacity from non-producing reserves is dependant on the assumed connection rates and the inherent assumption that all non-producing reserves will be connected within a specified time frame.

Projections of productive capacity from reserves additions are even less certain. Not only do they assume that the required level of drilling activity will occur, they also assume that future reserves additions will be connected at the required rates and that they will have producing characteristics similar to known established reserves.

FIGURE 6-45

Illustration of Relationship between Non-coincidental Peak Day and Average Day Supply
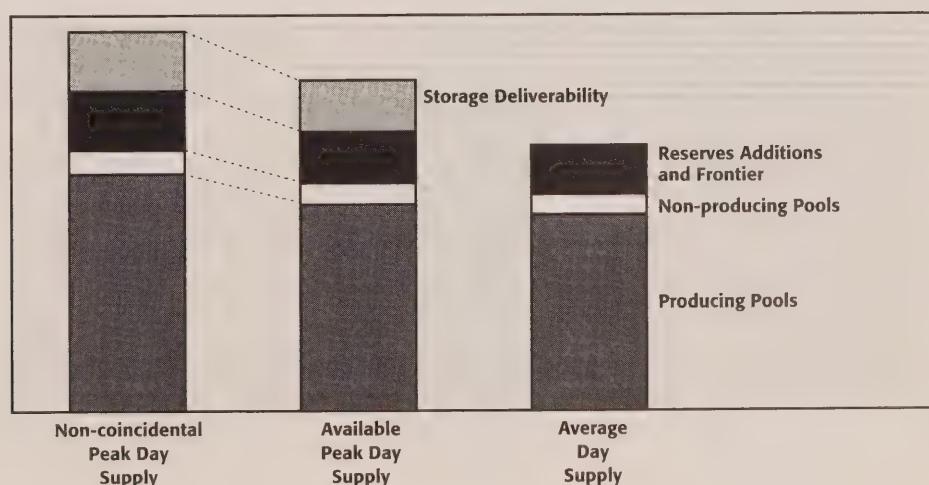
The changing relationship of productive capacity from each of the four components over time is shown in Figure 6-46.

6.8.3 Productive Capacity from Established Reserves

British Columbia

The modelling framework discussed above was used to project non-coincidental peak day productive capacity for all connected producing B.C. gas pools and two fields in the Yukon and Northwest Territories which are tied into the Westcoast pipeline system. Available peak day was estimated by reducing this projection by approximately five percent to account for unforeseen production problems. This adjustment factor is based on information in Westcoast's 1992 Five Year System Development Plan (Five Year Plan). An initial rate of take of 1:4 380 for producing pools in B.C. was found to yield good correlation with the estimated productive capacity for 1992. The current estimate of productive capacity for producing non-associated gas pools is 15.9 10^9m^3 per year (561 Bcf/yr). This is expected to decline over the projection period to about 1.6 10^9m^3 per year (56 Bcf/yr) by 2010.

The projection of productive capacity for associated and solution gas in B.C. is based on our oil production projection for B.C. In aggregate, we expect that the level of associated and solution gas production in B.C. will decline over the projection from 0.9 10^9m^3 per year (32 Bcf/yr) in 1993 to about 0.1 10^9m^3 per year (4 Bcf/yr) by 2010.

Productive capacity profiles for currently non-producing non-associated gas reserves in B.C. were calculated using our modelling framework for each of five areas: Fort St. John, Fort Nelson, Pine River, Mainline and Other. Connection rates for these non-producing pools were derived from both information provided by Westcoast and the known or anticipated gas processing plant capacities as appropriate. The connection rates used for these areas are shown in Appendix Table A6-8. Annual productive capacity from currently non-producing pools in B.C. is expected to grow from a current level of about 0.5 10^9m^3 per year (18 Bcf) to a maximum level of about 5.9 10^9m^3 per year (208 Bcf/yr) by 1999, declining thereafter to about 1.4 10^9m^3 per year (49 Bcf/yr) by the year 2010.

In total, productive capacity from established reserves in B.C. is expected to increase from its current level of about 17.3 10^9m^3 per year (611 Bcf/yr) to 19.8 10^9m^3 per year (699 Bcf/yr) in 1995, declining thereafter to about 3.2 10^9m^3 per year (113 Bcf/yr) by the year 2010. Our projections of productive capacity from established reserves in B.C. are shown in Appendix Table A6-9.

Our projections of productive capacity from established reserves in B.C. for the Current Technology and High Technology Cases differ by less than 1 percent in any given year. This is primarily because the technology assumptions for the two cases did not result in very different pool development schemes.

FIGURE 6-46

Components of Productive Capacity
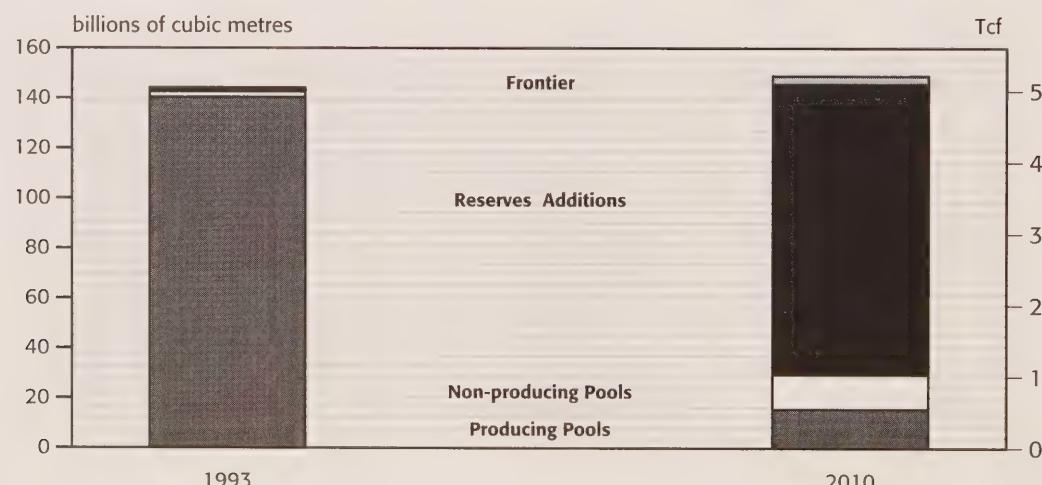
Alberta

The modelling framework discussed earlier was used to make a projection of non-coincidental peak day productive capacity for all connected producing Alberta gas pools. In establishing a representative rate of take for Alberta's connected producing gas pools, we summed the non-coincidental peak day rates for all Alberta gas pools over the 1992/93 heating season. A total non-coincidental peak day rate of approximately 395 $10^6m^3/d$ (13.9 bcf/d) was observed during the period October 1992 to March 1993. It was found that applying an initial rate-of-take of 1:2 800 to all producing pools enabled our model to best approximate the overall non-coincidental peak day during that winter period.

Available peak day productive capacity for producing pools in Alberta was estimated by reducing the non-coincidental peak day projection by 13 percent in 1993. This reduction reflects NOVA's experience that not all supply can be accessed simultaneously due to factors such as plant and field facilities reliability during extended periods of cold weather. The 13 percent factor was modified to 10 percent by 1996 (and held constant thereafter) to reflect the fact that the industry is gaining experience working in a balanced supply demand situation.

Our current projection of productive capacity for connected producing non-associated gas pools in Alberta is 83.6 10^9m^3 per year (3.0 Tcf/yr). This rate is expected to decline over the projection period to about 4.1 10^9m^3 per year (145 Bcf/yr) in 2010 for the Current Technology Case and 3.7 10^9m^3 per year (131 Bcf/yr) in 2010 in the High Technology Case. The small differences between the two cases result from the different levels of pool development that occur as a consequence of the different assumptions used for each case.

Productive capacity projections for the non-associated producing gas pools in Alberta were added to projections for the shallow gas pools of Southeastern Alberta, cycling gas pools and associated and solution gas pools. We used the same projections for each of these other supply components under both the Current and High Technology Cases.

We derived our productive capacity projections for the Milk River/Medicine Hat/Second White Specks shallow gas reserves in southeastern Alberta by field, using a production decline analysis approach. We examined the top 8 of the 31 producing areas in southeastern Alberta which represented approximately 94 percent of the 1992 shallow gas production. We projected the infill drilling required to fully develop these fields and to maintain a constant level of production

from the established reserves for as long as possible. The ERCB's projection, published in its "Ultimate Potential and Supply of Natural Gas in Alberta" (Report 92-A), was adopted for the remaining areas. Our projection of productive capacity from shallow gas reserves in southeastern Alberta declines from a current level of 7.7 10^9m^3 per year (272 Bcf/yr) to about 2.8 10^9m^3 per year (99 Bcf/yr) in 2010.

Our projections of productive capacity for associated and solution gas are based on our projection of the productive capacity for the relevant oil pools and a projection of gas to oil ratios in those pools. Productive capacity for associated and solution gas remains constant at the current level of 15.2 10^9m^3 per year (537 Bcf/yr) for five years and declines thereafter to about 4.4 10^9m^3 per year (155 Bcf/yr) in 2010.

Our projection of productive capacity from Alberta's cycling pools is based on information obtained from the ERCB for those pools and our estimate of each pool's reserves. The projection declines over the projection period from a current level of 8.9 10^9m^3 per year (314 Bcf/yr) to about 1.1 10^9m^3 per year by (39 Bcf/yr) the year 2010.

Overall our projection of productive capacity from connected producing reserves in Alberta declines from a current level of 115.4 10^9m^3 per year (4.1 Bcf/yr) to approximately 12.5 10^9m^3 per year (441 Bcf/yr) by 2010 in the Current Technology Case and 12.1 10^9m^3 per year (427 Bcf/yr) by 2010 in the High Technology Case.

The large number of non-producing gas pools and the difficulty in examining the location of these pools in relation to existing or proposed pipeline facilities dictated that we adopt a generalized approach to projecting connection rates for these pools. We expect that non-producing reserves will be connected over a period of time in a phased manner taking account of the industry's ability to physically connect new sources of supply, the time required to acquire firm transportation service and the likelihood that some reserves will require increased prices to become economic. The connection schedules for non-producing reserves in Alberta are shown in Appendix Table A6-10. For the Current Technology Case, we used the schedule discussed in our previous Supply/Demand report which assumes that all non-producing reserves will be connected over a ten year period. We recognize that changing market conditions could cause connections to occur somewhat faster or slower than those rates. Therefore, we assumed a slower connection schedule for the High Technology Case than for the Current Technology one because the total demand for Alberta gas remains relatively flat in the High Technology case over

the first ten years. These connection schedules for non-producing pools provide for pools which are currently uneconomic due to size and/or distance from existing facilities to become economic over the projection period as new facilities are built.

In our previous report, we concluded that it would be reasonable to assume that initial rates of take for currently non-producing Alberta reserves should reflect pool size, with smaller pools producing at the highest initial rate of take. In many cases smaller pools, especially single-well pools, are now being connected and produced at initial rates of take as fast as 1:2 000. Larger pools can be produced more economically at slower rates of take and generally tend to be produced in that manner. In this supply analysis, we continued to use those rates of take, namely:

- 1:5 250 for pools with initial reserves of 100 million cubic metres (3.5 Bcf) or more;

- 1:4 125 for pools with initial reserves between 30 and 99 million cubic metres (1 or 3.5 Bcf); and

- 1:3 000 for pools with initial reserves less than 30 million cubic metres (1 Bcf).

In the Current Technology Case, we project that productive capacity from currently non-producing non-associated gas pools in Alberta will increase from a current level of 1.8 10^9m^3 per year (64 Bcf/yr) to 34.2 10^9m^3 per year (1.2 Tcf/yr) in 2001, declining thereafter to about 12.5 10^9m^3 per year (441 Bcf/yr) in 2010. Similarly, in the High Technology Case, productive capacity increases to 29.9 10^9m^3 per year (1.1 Tcf/yr) in 2004 and declines thereafter to about 22.4 10^9m^3 per year (791 Bcf/yr) by the year 2010.

Overall, productive capacity from established reserves in Alberta is expected to grow from the current level of 117.2 10^9m^3 per year (4.1 Tcf/yr) to 130.7 10^9m^3 per year (4.6 Tcf/yr) in 1994 and decline thereafter to about 25.0 10^9m^3 per year (883 Bcf/yr) by 2010 in the Current Technology Case. In the High Technology Case, productive capacity from established reserves in Alberta is projected to increase to 130.6 10^9m^3 per year (4.6 Tcf/yr) in 1994 and decline thereafter to about 34.5 10^9m^3 per year (1.2 Tcf/yr) by 2010. Our projections of productive capacity from established reserves in Alberta are shown in Appendix Table A6-11.

Saskatchewan

In Saskatchewan, we estimated productive capacity for the major non-associated gas pools and the shallow gas pools within the modelling framework outlined earlier. We prepared an estimate of productive capacity from associated and solution gas pools based on the current level of production from those sources and based their decline on our projection of oil production for Saskatchewan. An estimate of current productive capacity for the small non-associated gas pools was derived based on current production information. The rate was then projected to decline exponentially over the projection period. Since non-producing pools represent a small faction of established reserves in Saskatchewan, we did not prepare a separate projection for those pools. We also assumed that productive capacity from established reserves in Saskatchewan would be the same under both Current and High Technology Cases.

Productive capacity from established reserves in Saskatchewan is projected to decline from a current level of 7.6 10^9m^3 per year (268 Bcf/yr) to about 1.3 10^9m^3 per year (46 Bcf/yr) in the year 2010. Our productive capacity projection from established reserves in Saskatchewan is shown in Appendix Table A6-12.

Eastern Canada

Our estimates of productive capacity for Ontario (and Quebec which has minor production) are based on historical trends. Productive capacity is expected to decline over the projection period from a current level of about 500 10^6m^3 per year (18 Bcf/yr) to approximately 100 10^6m^3 per year (4 Bcf/yr) in 2010.

Frontier

Under the Current Technology assumptions, frontier gas supply off the East Coast is expected to become viable. An offshore Nova Scotia project is anticipated to commence production in the year 2007 at a rate of about 3.3 10^9m^3 per year (116 Bcf/yr). In the High Technology Case, no frontier gas supply is projected to be required during the projection period as there would be adequate supply available from the WCSB. Neither of these cases assume that Mackenzie Delta gas will become available during the projection period because, in both cases, the assumptions of prices are too low and transportation costs are too high to make Delta gas economic within the projection period.

6.8.4   Productive Capacity from Reserves Additions

As mentioned in the discussion of the modelling framework, we assumed that reserves additions would be discovered and developed so as to maintain productive capacity over the longer term at a level some

10 percent higher than average projected annual production, or demand. Annual reserves additions are first determined for Canada as a whole. The modelling framework, within which we estimate reserves additions, examines the ongoing state of the supply/demand equilibrium and the price of natural gas. These factors combine to determine the rate at which reserves additions are to be connected. The tighter the supply/demand equilibrium and the higher the price of natural gas, the more likely reserves additions will be connected more quickly.

In the Current Technology Case, required reserves additions are expected to increase from a 1993 level of about 52 $10^9 m^3$ per year (1.8 Tcf/yr) to a level of 155 $10^9 m^3$ per year (5.5 Tcf/yr) in the year 2000, remain constant for six years and then decline to about 77 $10^9 m^3$ per year (2.7 Tcf/yr) by the year 2010. The decline in the requirement for reserves additions in the latter part of the projection period is due to lower projected demand levels and the start-up of frontier production in the year 2007.

In the High Technology Case, required reserves additions are expected to remain constant initially at about 39 $10^9 m^3$ per year (1.4 Tcf/yr), due to relatively low demand growth, particularly gas exports. After four years the required reserves additions increase throughout the remainder of the projection period, in response to rapid increases in demand, to a level of about 206 $10^9 m^3$ per year (7.3 Tcf/yr) in the year 2010. Figure 6-47 shows a comparison of the two reserves additions cases along with actual reserves additions over the years 1965 to 1992. Both projections are within the range of the historical data.

Projected total reserves additions were assigned to each of the three western producing provinces on the basis of their remaining reserves potential (Appendix Table A6-13). Because the development of the basin in B.C. is less mature than either Alberta or Saskatchewan, we expect that there will be more growth in the need for reserves additions from British Columbia. Otherwise, most of the remaining potential for gas in Alberta would have to be discovered before the year 2010. Figure 6-48 compares our estimated reserves additions for Alberta and B.C. for each of the two technology cases. The irregular historical pattern of reserves additions is due, in part, to the reserve revisions being allocated to the year they were adjusted, rather than the year they were actually incurred. In the Current Technology case, we project that, by the year 2010, 89 percent of our current estimate of Alberta's ultimate resource potential and 73 percent of British Columbia's ultimate resource potential will need to have been discovered. In the High Technology case, 90 percent of our current estimate of Alberta's ultimate reserves potential and 76 percent of British Columbia's ultimate reserves potential will need to be.

6.8.5   Total Productive Capacity

To our projections of productive capacity from established reserves in each producing region, we add productive capacity from reserves additions. Productive capacity from reserves additions for each of the three western producing provinces was estimated using a deliverability profile based on the characteristics of established reserves. The connection rates determined for reserves additions in the overall analysis of supply and demand described above were applied to these reserves additions for each province.

FIGURE 6-47
Historical and Projection of Reserves Additions
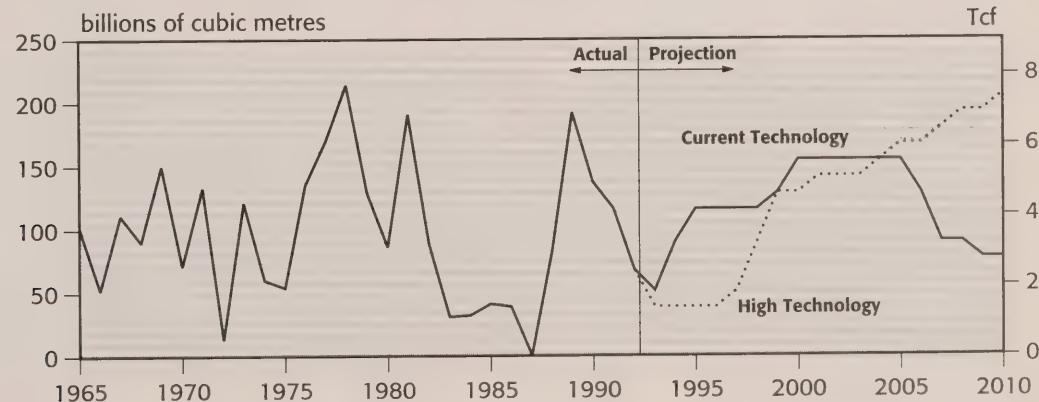
Current Technology case illustrations of total productive capacity for B.C., Alberta and Saskatchewan by supply component are found in the Appendix (Figures A6-3, A6-4 and A6-5). Total productive capacity in B.C. is projected to increase from the current level of 17.6 10^9m^3 per year (621 Bcf/yr) to a peak level of 36.3 10^9m^3 per year (1.3 Tcf/yr) in the year 2007, declining thereafter to approximately 34.6 10^9m^3 per year (1.2 Tcf/yr) by 2010. Total productive capacity in Alberta is expected to remain relatively constant over the first 14 years of the projection period at an average rate of about 126 10^9m^3 per year (4.4 Tcf/yr), declining thereafter to about 107.1 10^9m^3 per year (3.8 Tcf/yr) by 2010. Productive capacity in Saskatchewan is expected to decline over the period from a current level of 7.8 10^9m^3 per year (275 Bcf/yr) to about 3.7 10^9m^3 per year (131 Bcf/yr) in the year 2010.

High Technology case illustrations of total productive capacity for B.C., Alberta and Saskatchewan by supply component are found in the Appendix (Figures A6-6, A6-7 and A6-8). Total productive capacity in B.C. is projected to increase from the current level of 17.6 10^9m^3 per year (621 Bcf/yr) to a peak of some 41.0 10^9m^3 per year (1.4 Tcf/yr) in the year 2010. After increasing due to field development in 1994, Alberta productive capacity is expected to decline initially from the 1994 level of 132.2 10^9m^3 per year (4.7 Tcf/yr) to a low of 89.4 10^9m^3 per year (3.2 Tcf/yr) in the year 2000 and then increase to a level of 135.1 10^9m^3 per year (4.8 Tcf/yr) by the year 2010. Productive capacity in Saskatchewan is projected to decline from the current level of 7.8 10^9m^3 per year (275 Bcf/yr) to about 3.8 10^9m^3 per year (134 Bcf/yr) in the year 2010.

FIGURE 6-48

Natural Gas Reserves Additions – Alberta-B.C. – Comparison of Cases
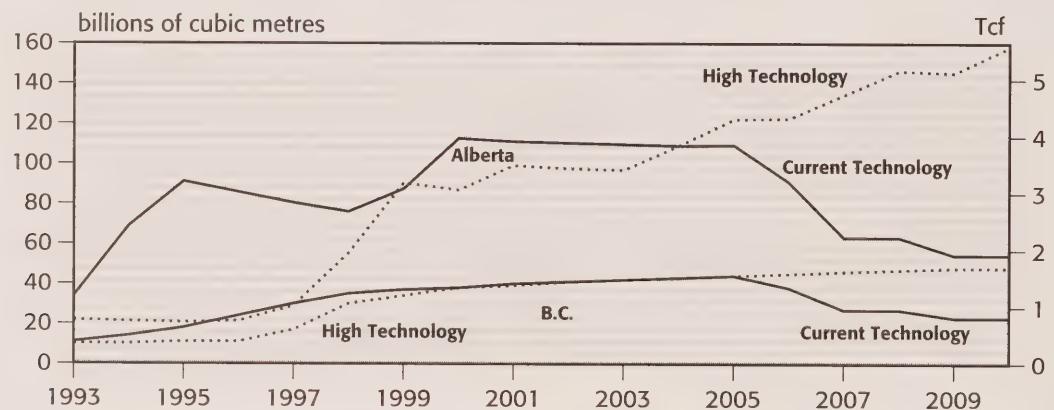
FIGURE 6-49

Productive Capacity of Natural Gas – Comparison with 1991 Control Case
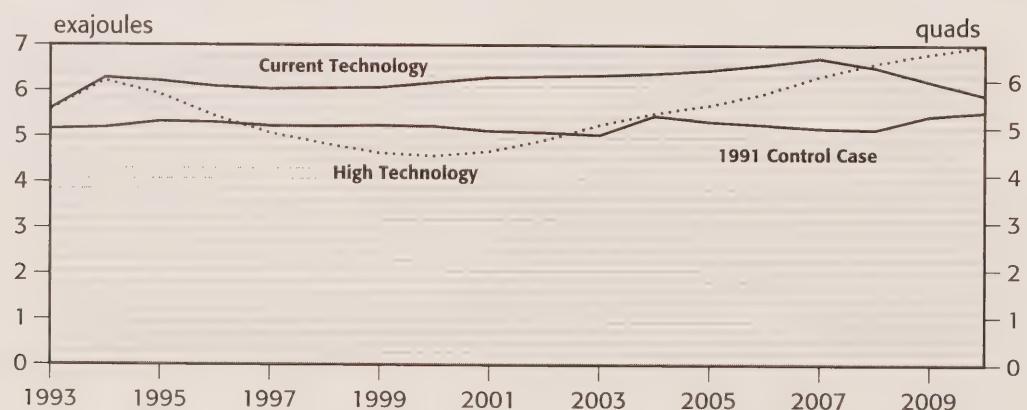
The projections of total productive capacity for Canada by producing region are illustrated in Appendix Figures A6-9 and A6-10 and are summarized in Appendix Tables A6-14 and A6-15 for the Current and High Technology cases respectively. Note that the overall shape of these projections is dominated by the shape of the Alberta projections referenced earlier.

A comparison of the Current and High Technology case projections of productive capacity with the Control Case projection from the 1991 Supply/Demand Report is provided in Figure 6-49. The differences are mainly due to the higher demand projections used in the 1994 analysis.

6.8.6 Natural Gas Supply and Demand

Figures 6-50 and 6-51 illustrate overall comparisons of natural gas supply and demand. The figures show the relative amount of domestic and export demand over the projection period. The adjusted productive capacity curve demonstrates the approximate 10 percent cushion of supply over demand that was projected in order that both peak day and annual demand would be satisfied.

Figures 6-52 and 6-53 also compare natural gas supply and demand. These figures show the relative amounts of productive capacity projected to come from established reserves, reserves additions and frontier over the projection period.

We have also estimated the level of production for each of the producing regions of Canada under both Current and High Technology cases based on the total demand for gas and the relative levels of projected productive capacity for the regions. These projections are illustrated in Appendix Figures A6-11 and A6-12.

FIGURE 6-50

Natural Gas Supply and Demand – Current Technology Case
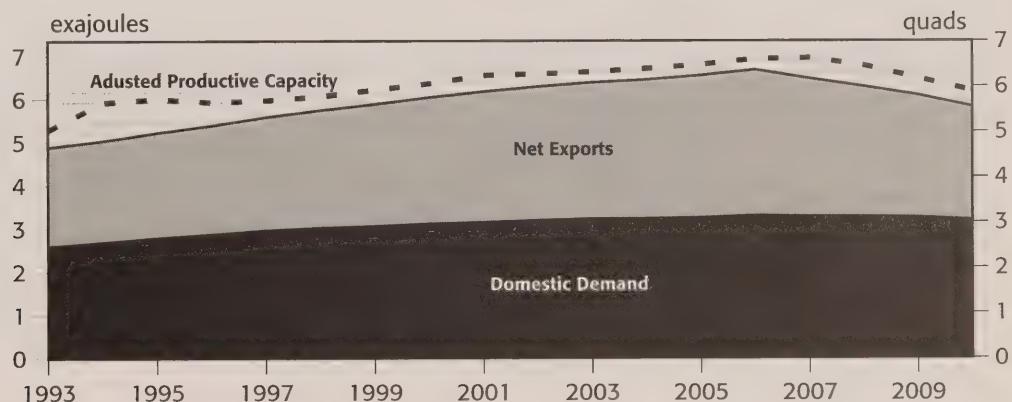
FIGURE 6-51

Natural Gas Supply and Demand – High Technology Case
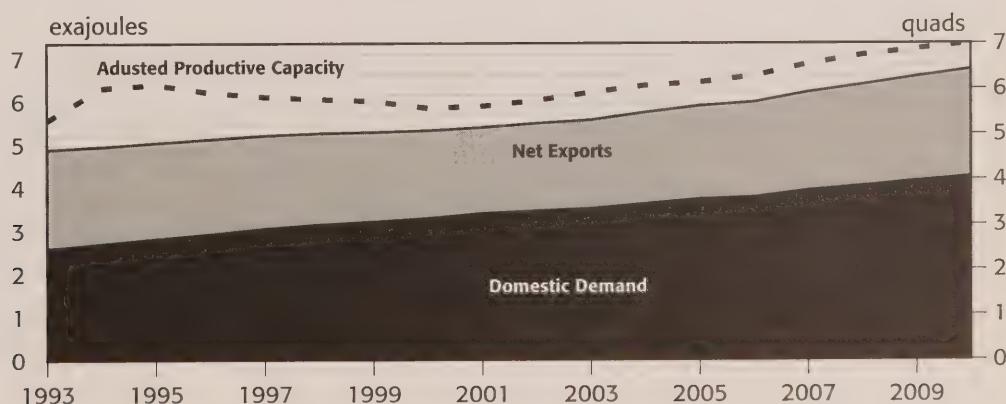
Finally, a comparison of projected natural gas production for B.C. and Alberta for the Current and High Technology cases is presented in Figure 6-54.

6.8.7   Drilling Activity

In order to assess the implication of the levels of reserves additions discussed earlier, we estimate the level of gas-directed exploratory drilling effort that would be required. We do this by using a relationship between cumulative metres drilled and initial established reserves over time. We developed a "best-fit" regression of the historical data for each of the producing provinces and used the established relationship for the fit of the data to estimate gas directed exploratory drilling effort. An example of the fit of the data is shown in Figure 6-55 for the province of Alberta.

The analysis described above results in a projection of drilling activity in the Current Technology case that grows from the current level (1993) of $1.9 \ 10^6$ metres of gas-directed exploratory drilling to a peak of $4.9 \ 10^6$ metres in the year 2005, declining thereafter to about $2.6 \ 10^6$ metres in 2010.

There are inherent difficulties in estimating drilling activity in the High Technology case because of its unknown effects. We have, therefore, made a simplifying assumption that there would ultimately be a 30 percent improvement in the ratio of reserves found per metre drilled i.e., an improvement of about two percent per year. We assumed that this improvement would be achieved over the next ten years. Gas-directed drilling activity in the High Technology case was estimated to decline initially to about $0.8 \ 10^6$ metres by

FIGURE 6-52

Comparison of Natural Gas Supply and Demand – Current Technology
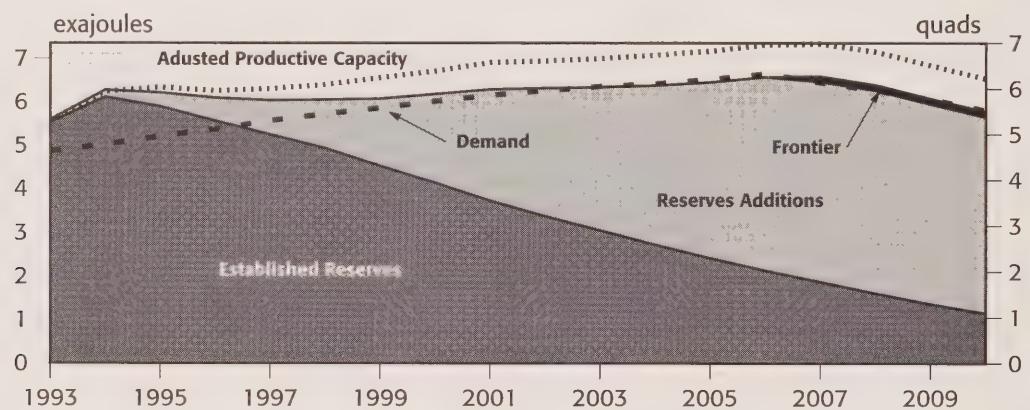
FIGURE 6-53

Comparison of Natural Gas Supply and Demand – High Technology
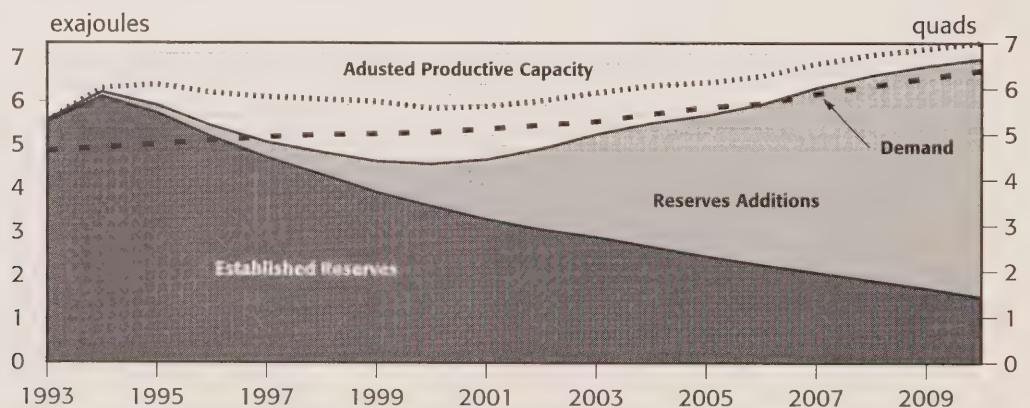
1996 and then to increase over the projection period to reach a high of 4.5 10^6 metres in the year 2010. A comparison of the projected gas directed exploratory drilling activity for both the Current Technology and High Technology cases is illustrated in Figure 6-56 and Appendix Table A6-16. Note that both cases require gas directed drilling activity in excess of the historical high of 3.4 10^6 metres that occurred in the year 1980. Also, the rate of increase in drilling activity for each case is similar to the rate of increase observed between 1975 and 1980.

Figure 6-57 illustrates the distribution of gas directed drilling activity between the provinces of Alberta and B.C. over the projection period. The projected decline in activity in the latter years of the projection due to decreased demand and the startup of frontier production is evident in the analysis for both Alberta and B.C. in the Current Technology case.

Total exploratory drilling is obtained by adding our projections of gas directed and oil directed exploratory drilling for each of the two cases. Figure 6-58 illustrates both the total and the division of exploratory drilling for the Current and High Technology cases. In total, projected drilling activity does not greatly exceed historical levels of activity, but it must be sustained without significant downward cycles.

6.8.8 Observations

One important observation is that the projected levels of drilling activity, while not significantly higher

FIGURE 6-54

Natural Gas Production – Alberta-B.C. – Comparison of Cases
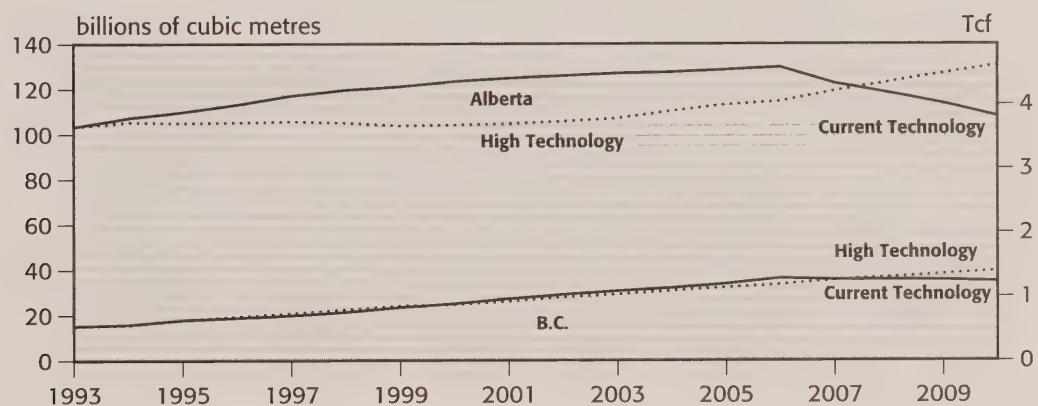
FIGURE 6-55

Drilling Activity – Alberta – Cumulative Metres Drilled as a Function of Established Reserves
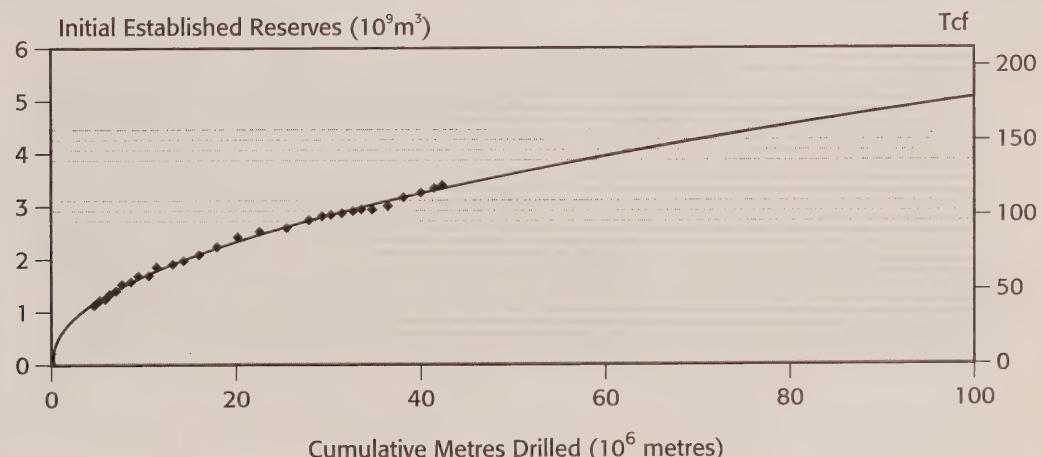
FIGURE 6-56
Historical and Projection of Drilling Activity
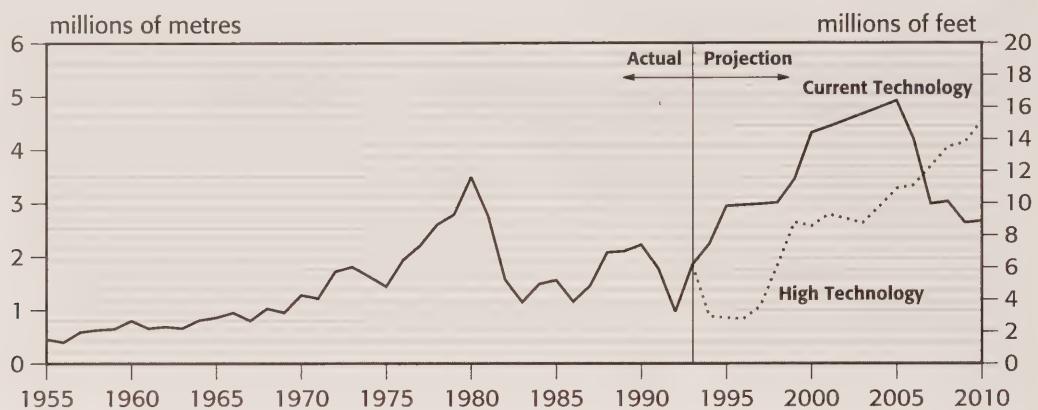
FIGURE 6-57
Gas-Directed Exploratory Drilling Activity – Alberta-B.C. – Comparison of Cases
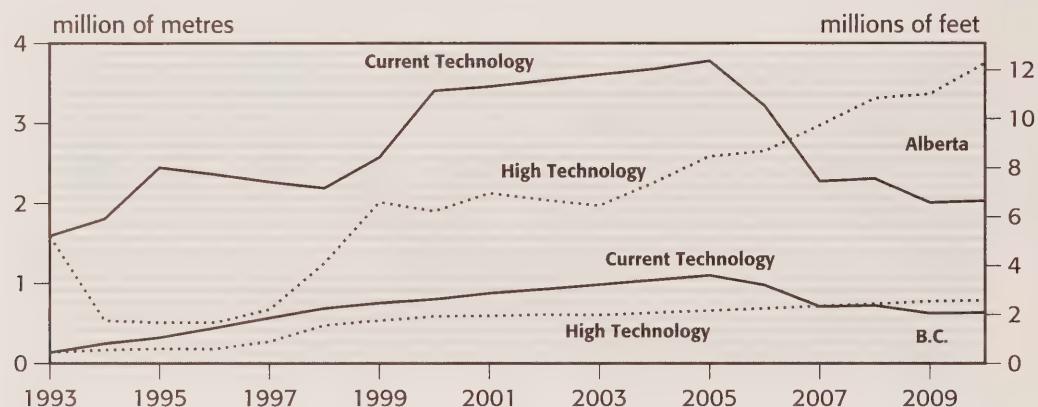
FIGURE 6-58
Division of Exploratory Drilling – Current (CT) and High Technology (HT) Cases
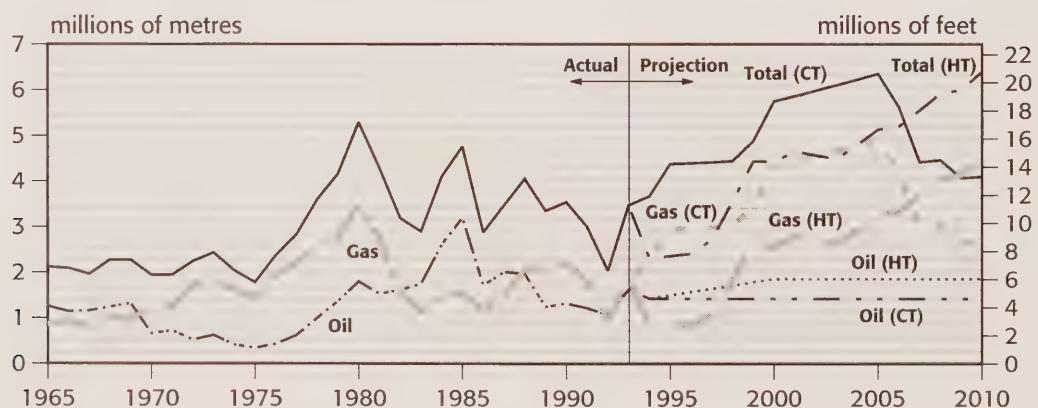
in total than historically achieved, do demonstrate that rapid increases in gas directed exploratory drilling will be required to satisfy the projected demand for Canadian gas. The focus on drilling will have to shift from the current trend in development drilling to active and successful gas-directed exploratory drilling. In our analysis, the largest producing region, Alberta, appears to be most affected by the High Technology assumptions. While drilling activity is unlikely to initially decline as much as the analysis suggests, higher levels of activity may result in higher reserves additions than projected in the early years of the analysis. This could lead to levels of excess productive capacity similar to those developed in the early 1980s.

Another equally important observation relates to the source of future reserves additions depicted in our analysis. We have shown a significant growth in the contribution of future reserves from British Columbia. We believe that this increase in reserves additions is reasonable given the relative immaturity of the development of natural gas resources in British Columbia as compared to Alberta. While drilling activity in British Columbia may not increase as rapidly as indicated, it will clearly be necessary for that province to play an ever-increasing role in supplying natural gas to markets east of British Columbia.

It is apparent that new pipeline interconnections and expansions will be required. With the greatest potential for market growth east of B.C., it is unlikely that pipeline capacity will be expanded to carry all of the projected increase in production south through British Columbia. It is more likely that there will be pressure to construct high capacity pipeline links to the NOVA system for transportation of a portion of future British Columbia gas production.

A final observation pertains to the remaining reserves to production ratios (RR/P) for each of the two cases. The projections of productive capacity demonstrate that the RR/P for the WCSB will continue its historical decline throughout the projection period. Figure 6-59 shows that the RR/P for connected and unconnected reserves is expected to decline slowly over the period from a level in 1993 of about 16 to a level in 2010 of about 9. This could imply that over the projection period, reserves additions would not be adequate to replace cumulative production over the same period. It could also mean that greater reliance would be placed on more efficient exploitation of the resource base over time.

6.9   EXPORT IMPACT ASSESSMENT

6.9.1   Introduction

The Export Impact Assessment (EIA) is one of the three parts of the Market Based Procedure (MBP), the method by which the National Energy Board assesses applications for long-term natural gas export licences. The other two components of the MBP are: The Complaints Procedure which allows Canadian purchasers to assess the terms and conditions of natural gas exports and bring any complaint regarding these to the attention of the Board; and Public Interest Determination in which the Board determines such matters as supply, producer support and transportation arrangements for exports. In addition, the Board conducts an on going monitoring of Natural Gas markets through publications such as the

FIGURE 6-59
RR/P Ratios in the WCSB – Comparison of Cases
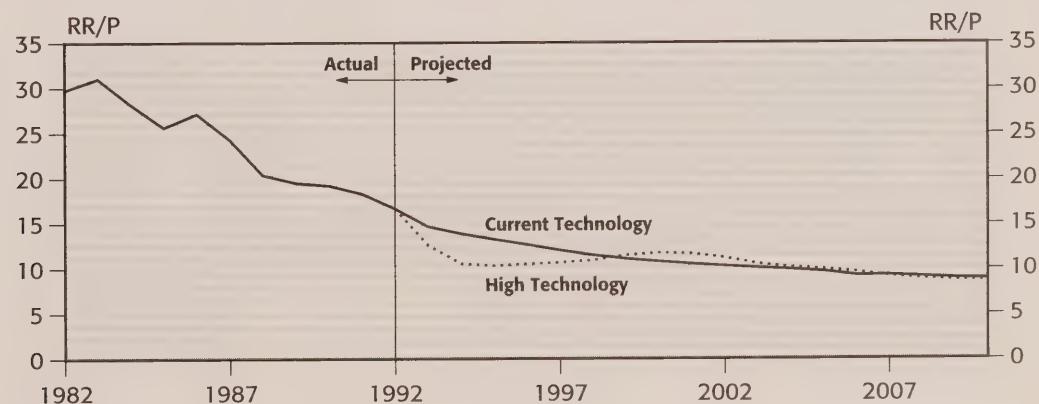
Supply and Demand Report and the natural gas Market Assessment. The purpose of the EIA is to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

At the initiation of the MBP (1987) the Board required applicants to submit their own EIA. However, it became apparent to the Board that it would be difficult to measure substantial impacts of small export volumes and it was unclear to the applicants how to best satisfy the EIA requirements. In November 1989 the Board issued a decision that retained the EIA, and that applicants are no longer required to file project specific analyses. The Board stated it would:

"periodically produce an EIA using several projections of exports. The study, which will be prepared in consultation with the natural gas industry and other interested parties will cover long-term natural gas supply, demand, prices and export levels and will endeavour to provide an adequate statement of assumptions and explanation of the analytical technique used."

The NEB has conducted two previous Export Impact Assessments one in 1989 and one in 1992. At the EIA workshop in April 1993[26], it was concluded that:

"the Board should continue to publish an EIA" and that "the EIA can benefit in the context of the more comprehensive Supply/Demand Report."

While there have not been formal consultations on this EIA per se, the main economic assumptions, oil price, natural gas resources, case development and modelling techniques were discussed at the April 1993 EIA workshop and during the initial round of consultations in May 1993 with a broad cross-section of government agencies, producing companies, pipelines and consumer groups. The preliminary results were also presented to a similar group in late 1993.

The purpose of this assessment is to analyze the implications of increased U.S. and Canadian demand on domestic supply, exports and Canadian burner tip prices. Therefore, the EIA is based on three sensitivity cases relative to the Current and High Technology cases. The High U.S. Demand and the Low Cost Supply cases were discussed in Section 6.7. The Low Cost Supply case is a departure from previous EIAs in that it shows the effect of additional supply on the upstream industry in terms of fieldgate prices and export volumes. The third case analyzed incorporates the "Alternate macro demand"

(higher Canadian demand for natural gas, see Chapter 4) which has been combined with the High U.S. Demand case and the High Technology case. The assumptions and framework for the analysis are set-out in the preceding sections of this chapter and in the relevant chapters on oil price and demand (Chapters 3 and 4).

This analysis is more suited to displaying long-term trends in prices, production, exports and demand than to measure short-term fluctuations associated with adjustments. The nature of the modelling technique (equilibrium modelling) determines that "adjustment difficulties" are not addressed explicitly. Nevertheless, the equilibrium results do illustrate the direction and magnitude of any adjustment required.

The results displayed below are summaries of those presented in the comparison of the two technology cases (Section 6.6) and the sensitivity cases (Section 6.7). In these results comparisons are made within each technology case, i.e., the High U.S. Demand and Low Cost Supply sensitivities, under the Current Technology assumptions are compared only to the "base" Current Tech case. A general comparison of Current Tech and High Tech results is made in the summary section. These data depict fieldgate prices, provincial production, total and regional exports, Canadian end use prices and Canadian demand.

6.9.2   Results – Current Technology

Fieldgate Prices

Table 6-15 shows the projections for the base case and the ratio of prices for the two sensitivity cases as well as the results from the 1992 EIA Control case. The High U.S. Demand case shows that prices may be eight to 15 percent higher than the base. The Low Cost Supply case indicates that prices could be about five percent less than the base. The price projection from the 1992 EIA Control case was higher than those of the High Demand case except for 2011.

Alberta Production

Provincial production for Alberta is shown on Table 6-16 The High U.S. Demand case peaks at about 1 Tcf/year higher than the base in 2001 and remains slightly higher in 2006 before declining to about 1 Tcf/year lower in 2011. The Low Cost Supply case is about 0.4 Tcf/year lower in the middle of the projection period before recovering to the same levels as the base

26 Export Impact Assessment Workshop, A Summary of Discussion, NEB, 1 April 1993.

case in 2011. All cases are substantially higher than the 1992 EIA projection.

B.C. Production

B.C.'s production is indicated on Table 6-17. In the High U.S. Demand case production is at or below the base case levels until 2006 when a rapid increase is indicated. The Low Cost Supply case is only lower than the base in 2006. As with Alberta, the projection for B.C. is significantly higher than the 1992 EIA.

Canadian Exports

Total Canadian exports, net of imports, are shown on Figure 6-60. In the High Demand case exports are almost 1 Tcf/year higher than the base case in 2006. In the Low Cost Supply case exports are about 0.5 Tcf/year lower than the base until 2011 when they are the same. The projections from the 1992 EIA are consistently lower, by 0.6 to 1.1 Tcf/year.

TABLE 6-15

Alberta Fieldgate Prices – Current Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	1.58	1.86	2.26	3.09	4.33
Ratios To Base Case					
High U.S. Demand	1.00	1.02	1.08	1.14	1.15
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	1.00	0.84	0.96	0.96	0.94
1992 EIA Control Case	1.11	1.27	1.42	1.25	1.06

*Ratio to Base Case = Sensitivity Case/Base Case

TABLE 6-16

Alberta Production – Current Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	3.4	4.1	4.6	5.2	4.2
Differences From Base Case					
High U.S. Demand	0.0	0.1	1.0	0.3	-1.0
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	0.0	0.0	-0.4	0.0	0.0
1992 EIA Control Case	0.0	-0.5	-0.9	-1.9	-1.2

*Difference from Base Case = Sensitivity Case – Base Case

TABLE 6-17

B.C. Production – Current Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.6	0.9	1.2	1.3	1.4
Differences From Base Case					
High U.S. Demand	0.0	0.0	-0.3	0.5	0.3
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	0.0	0.0	0.0	-0.6	0.0
1992 EIA Control Case	-0.2	-0.4	-0.7	-0.6	-0.7

Regional Exports

Figures 6-61 to 6-64 inclusive, show the export projections to the four major U.S. market regions for the base case. In the High Demand case, the Central and Northeast regions show similar increases in the 1996 to 2006 period and decline in 2011 (Tables 6-18 and 6-19). Of particular note is the strong demand for Canadian gas in the Northeast/Mid-Atlantic region in 2001 and 2006. In California and the Pacific Northwest (Tables 6-20 and 6-21), increases are only evident toward the end of the projection. In the Low Cost Supply case both the Northeast/Mid-Atlantic and the Central regions show modest declines of 0.1 to 0.2 Tcf/year in the period from 2001 to 2006. California and PNW volumes are virtually unchanged throughout the projection period.

Canadian Burner Tip Price

Tables 6-22 and 6-23 show the burner tip prices for the industrial sector in the Ontario and Quebec markets with the ratios for the sensitivity cases. As would be expected these prices respond in the same fashion as the fieldgate price, although the rates of increase are somewhat less since pipeline tolls are constant in real terms. The Quebec and Ontario prices are eight to 10 percent higher in the High Demand case and one to three percent lower in the Low Cost Supply case. Even the High U.S. Demand prices are five to 15 percent lower than the 1992 EIA Control case.

Canadian Demand

Table 6-24 shows that Canadian demand is little affected in either sensitivity case, small volumes (0.1 Tcf/year) are lost with the High U.S. Demand case and

there is no measurable increase in the Low Cost Supply case. Average demand in the Current Technology case is about 0.2 Tcf/year higher than the 1992 EIA Control case.

6.9.3 Results – High Technology

Fieldgate Prices

Table 6-25 shows the projections for the base case and the ratio of prices for the three sensitivity cases as well as the results from the 1992 EIA Control case. The High U.S. Demand case shows that prices could be five to 18 percent higher than the base. The High Canadian Demand has little impact on fieldgate prices, which are about one to two percent higher than the High U.S. Demand case. The Low Cost Supply case indicates that prices could be about seven to 10 percent less than the base. All price projections from the 1992 EIA Control case were higher, by a considerable margin, than even the High U.S. Demand case.

Alberta Production

Provincial production for Alberta is shown on Table 6-26. The High U.S. Demand case is about 0.7 Tcf/year higher than the base through most of the projection. The High Canadian Demand case does not appear to have an effect on Alberta production until after 2001. The Low Cost Supply case averages about 0.7 Tcf/year lower after 2001. All cases are substantially higher than the 1992 EIA projection.

B.C. Production

B.C.'s production is indicated on Table 6-27. In the High U.S. Demand case, production is about the same

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FIGURE 6-60

Canadian Exports – Current Technology
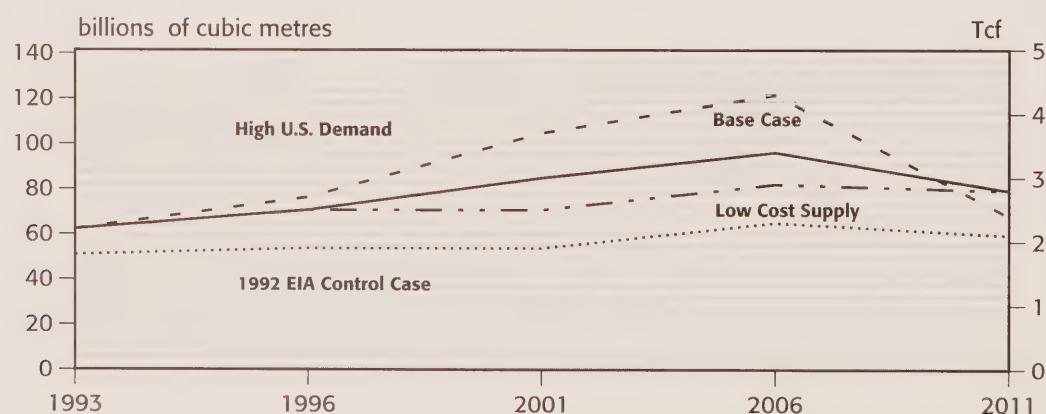
FIGURE 6-61
Current Technology Exports and Imports – 1993
Tcf/Yr
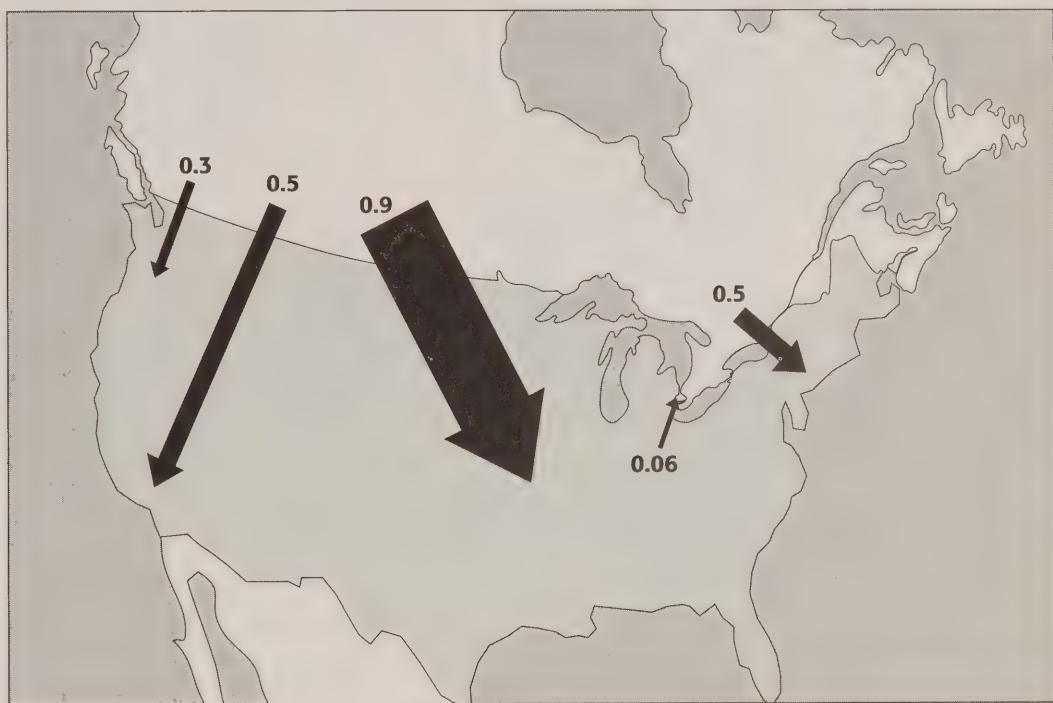
FIGURE 6-62
Current Technology Exports and Imports – 2001
Tcf/Yr
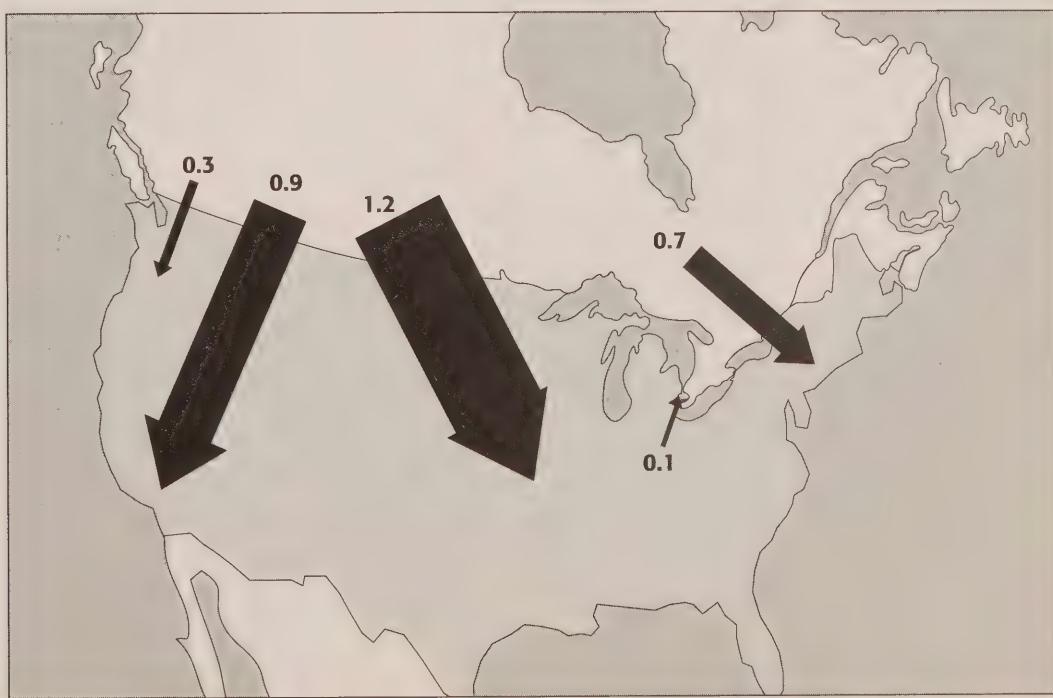
FIGURE 6-63
Current Technology Exports and Imports – 2006
Tcf/Yr
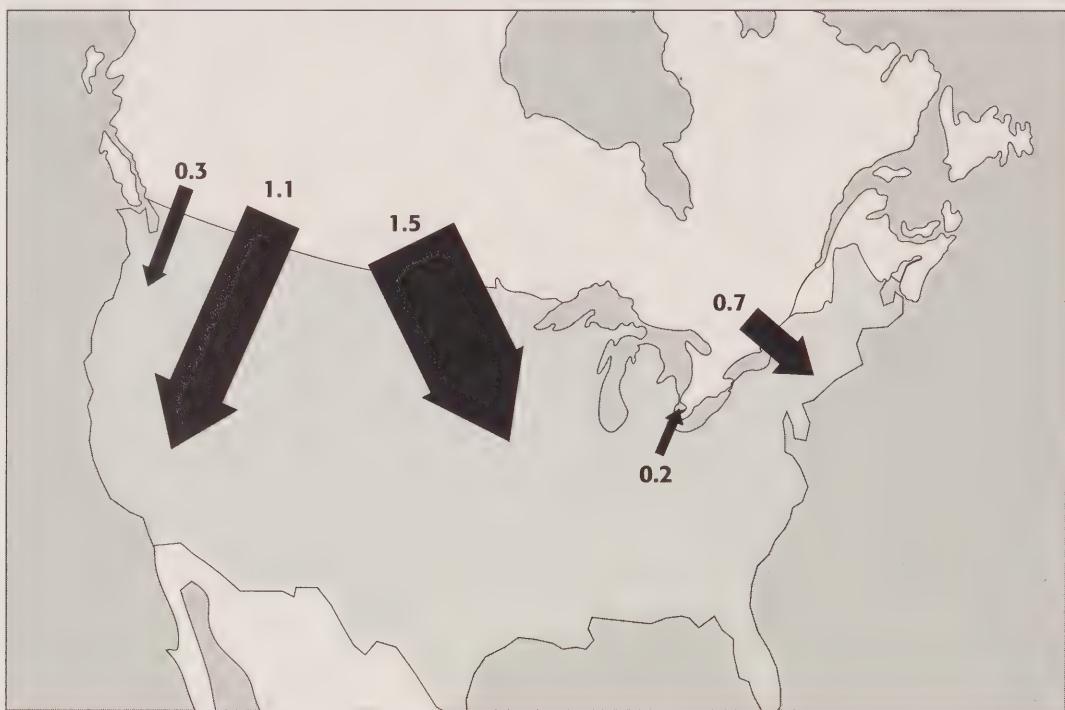
FIGURE 6-64
Current Technology Exports and Imports – 2011
Tcf/Yr
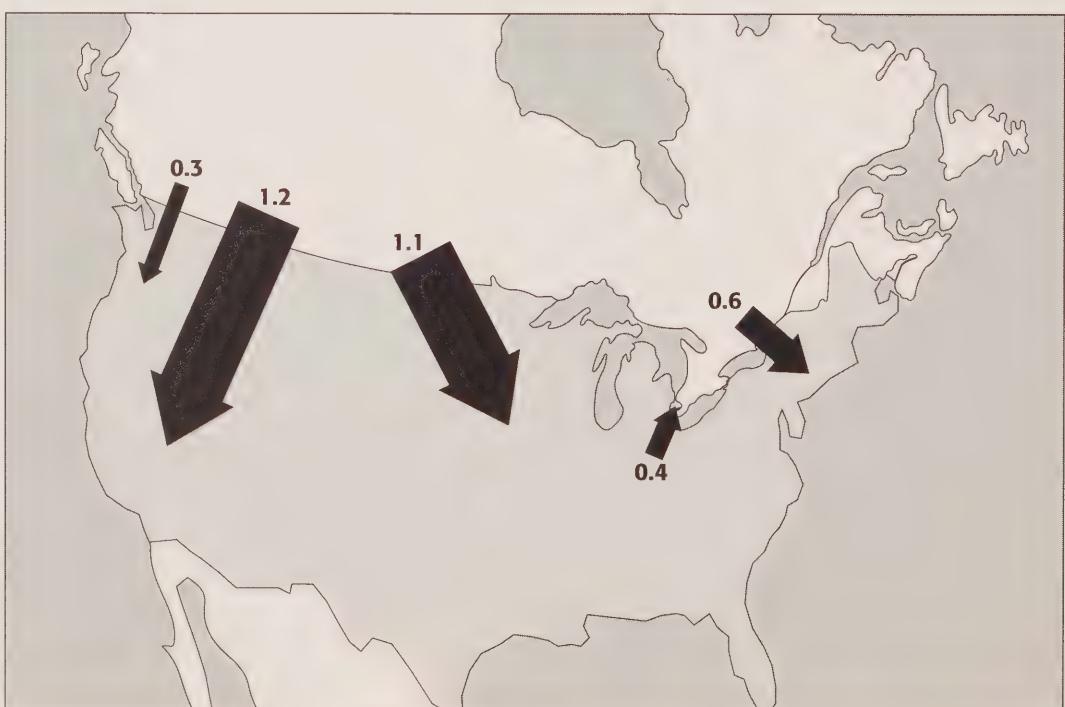
TABLE 6-18

Exports To Northeast/Mid-Atlantic – Current Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.5	0.5	0.7	0.7	0.6
Differences From Base Case					
High U.S. Demand	0.0	0.1	0.5	0.1	0.0
Low Cost Supply	0.0	0.0	-0.2	-0.2	-0.1

TABLE 6-19

Exports To Central Region – Current Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.9	1.2	1.2	1.5	1.1
Differences From Base Case					
High U.S. Demand	0.0	0.1	0.2	0.0	0.0
Low Cost Supply	0.0	0.0	-0.1	-0.2	0.0

TABLE 6-20

Exports to California – Current Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.5	0.7	0.9	1.1	1.2
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.0	0.3	0.2
Low Cost Supply	0.0	0.0	0.0	0.0	0.0

TABLE 6-21

Exports To Pacific Northwest – Current Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.3	0.2	0.3	0.3	0.3
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.0	0.3	0.0
Low Cost Supply	0.0	0.0	0.0	-0.1	0.0

TABLE 6-22

TABLE 6-22

Ontario Industrial Burner Tip Prices – Current Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	3.24	3.66	4.31	5.40	7.11
Ratios To Base Case					
High U.S. Demand	1.00	1.01	1.05	1.09	1.10
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	1.00	0.92	0.98	0.98	0.97
1992 EIA Control Case	1.09	1.14	1.22	1.15	1.05

TABLE 6-23

Québec Industrial Burner Tip Prices – Current Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	4.36	4.84	5.57	6.76	8.63
Ratios To Base Case					
High U.S. Demand	1.00	1.01	1.04	1.08	1.09
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	1.00	0.94	0.99	0.99	0.98
1992 EIA Control Case	1.08	1.10	1.17	1.12	1.04

TABLE 6-24

Canadian Demand – Current Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	2.3	2.4	2.7	2.8	2.7
Differences From Base Case					
High U.S. Demand	0.0	0.0	-0.1	-0.1	-0.1
High Canadian Demand	N/A	N/A	N/A	N/A	N/A
Low Cost Supply	0.0	0.0	0.0	0.0	0.0
1992 EIA Control Case	0.2	0.4	0.2	0.2	0.2

TABLE 6-25

Alberta Fieldgate Prices – High Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	1.58	1.51	1.39	1.79	2.35
Ratios To Base Case					
High U.S. Demand	1.00	1.18	1.05	1.11	1.06
High Canadian Demand	1.00	1.19	1.06	1.12	1.07
Low Cost Supply	1.00	0.88	0.93	0.89	0.90
1992 EIA Control Case	1.11	1.99	2.30	2.16	1.96

as the base case, being slightly higher in 2001 and slightly lower in 2006. The High Canadian Demand case increases this province's production by small amounts (0.1 Tcf/year). The Low Cost Supply case also has little effect on B.C. production being 0.3 Tcf/year lower than the base in only one period (2006). As with Alberta, the projection for B.C. is significantly higher than the 1992 EIA.

Canadian Exports

Total Canadian exports, net of imports, are shown on Figure 6-65. In the High U.S. Demand case exports are almost 0.5 to 0.9 Tcf/year higher than the base case. The High Canadian Demand does not reduce any exports to the U.S. In the Low Cost Supply case exports average about 0.7 Tcf/year lower than the base through the projection period. The projections from the 1992 EIA are marginally lower until 2011, when the differential is lower by 1 Tcf/year.

Regional Exports

Figures 6-66 to 6-68 inclusive show the export projections to the four major U.S. market regions for the base case. In the High U.S. Demand case, the Northeast/Mid-Atlantic region (Table 6-28) shows average increases of about 0.3 Tcf/year through the projection, and the Central region (Table 6-29) shows a peak in 2001, the other years being similar to the base case. In California and the Pacific Northwest (Tables 6-30 and 6-31), only small increases (0.1 Tcf) are evident. In the Low Cost Supply case both the Northeast/Mid-Atlantic and the Central regions show modest declines of 0.2 to 0.3 Tcf/year in the period from 2001 to 2006. California and PNW volumes are virtually unchanged throughout the projection period.

Canadian Burner Tip Prices

Tables 6-32 and 6-33 show the burner tip prices for the industrial sector in the Ontario and Quebec markets with the ratios for the sensitivity cases. The Quebec and Ontario prices are two to seven percent higher in the High U.S. Demand case and two to five percent lower in the Low Cost Supply case. The High Canadian Demand case has only a small effect on burner tip prices, which are about one percent higher than the High U.S. Demand case. The 1992 EIA Control case indicates higher prices than even the High U.S. Demand by a margin of 40 to 50 percent.

TABLE 6-26

Alberta Production – High Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	3.4	3.7	4.1	4.7	6.0
Differences From Base Case					
High U.S. Demand	0.0	0.1	0.7	0.6	0.7
High Canadian Demand	0.0	0.1	0.7	0.6	0.7
Low Cost Supply	0.0	-0.1	-0.9	-0.3	-0.9
1992 EIA Control Case	0.0	-0.1	-0.4	-1.4	-3.0

TABLE 6-27

B.C. Production – High Technology

Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.6	0.7	1.2	1.3	1.0
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.2	-0.1	0.0
High Canadian Demand	0.0	0.1	0.2	0.0	0.1
Low Cost Supply	0.0	0.0	0.0	-0.3	0.2
1992 EIA Control Case	-0.2	-0.2	-0.7	-0.6	-0.3

Canadian Demand

Table 6-34 indicates that Canadian demand would be unchanged in the High U.S. Demand case, while it increases marginally throughout the projection when the High Canadian Demand is combined with the High U.S. Demand case. In the Low Cost Supply case a small increase is apparent in 2011. The demand in the base case is lower than the 1992 EIA control case by 0.3 to 0.9 Tcf/year in 2006 and 2011 respectively.

6.9.4   Export Impact Assessment Summary

Under the Current Technology case, average fieldgate prices show an increase of up to 15 percent, if the High U.S. Demand materializes. The Low Cost Supply case indicates an erosion of prices in Canada. The maximum range of fieldgate prices in 2011, between these sensitivity cases is indicated to be $4.09 to $4.86 per gigajoule. A similar effect is visible on the range of burner tip prices in Ontario ($6.92 to $7.85) and Québec ($8.46 to $9.41), but the effect is somewhat more muted (11 percent change vs 20 percent) as transportation and distribution costs are held constant for all cases.

Production in Alberta responds in the medium term to the increased demand, but by 2011 gas has lost market share to HFO (Section 6.6.2.8 – U.S Fuel Switching). B.C. does not realize any benefit from increased production in the early part of the projection, but gains substantially after 2006. The introduction of new supply has little effect on production in either Alberta or B.C.,

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TABLE 6-28

Exports To Northeast/Mid-Atlantic – High Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.5	0.5	0.5	0.7	0.7
Differences From Base Case					
High U.S. Demand	0.0	0.1	0.3	0.4	0.2
Low Cost Supply	0.0	0.0	-0.2	-0.2	-0.3

TABLE 6-29

Exports To Central Region – High Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.9	1.0	1.0	1.0	1.4
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.4	0.1	0.1
Low Cost Supply	0.0	0.0	-0.3	-0.2	-0.3

TABLE 6-30

Exports To California – High Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.5	0.6	0.8	0.9	1.1
Differences From Base Case					
High U.S. Electric Demand	0.0	0.0	0.0	0.0	0.1
Low Cost Supply	0.0	0.0	0.0	0.0	0.0

FIGURE 6-65
Canadian Exports – High Technology
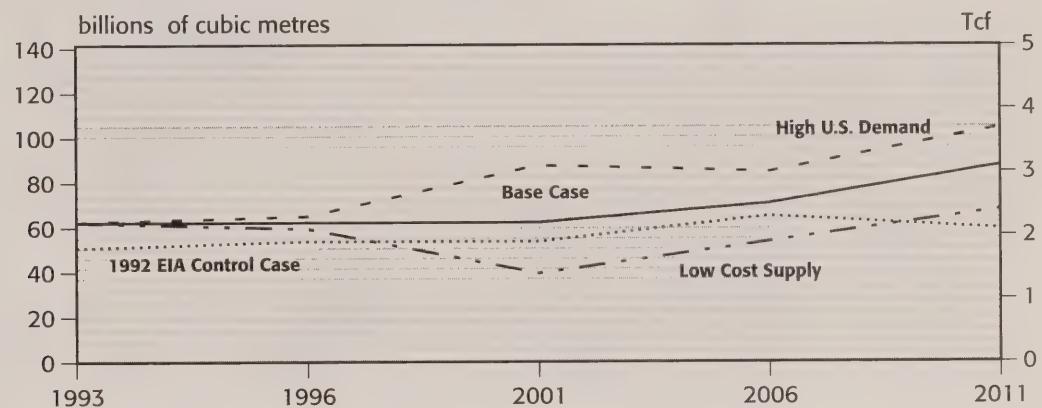
FIGURE 6-66
High Technology Exports and Imports – 2001
Tcf/Yr

FIGURE 6-67
FIGURE 6-67
High Technology Exports and Imports – 2006
Tcf/Yr
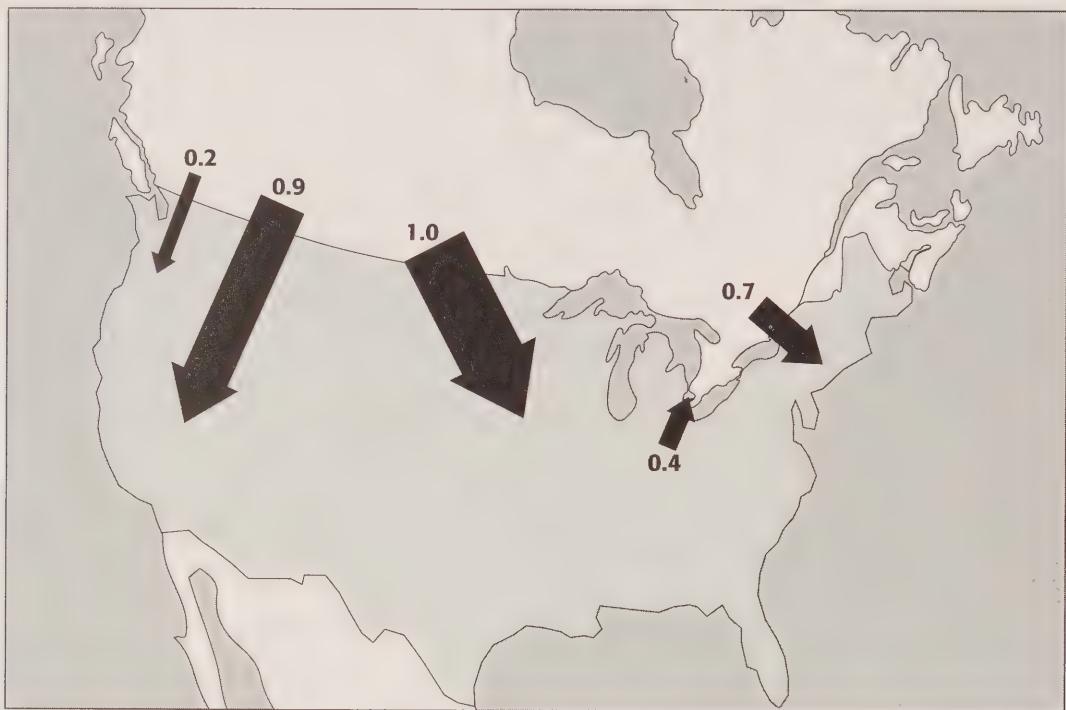
FIGURE 6-68
High Technology Exports and Imports – 2011
Tcf/Yr
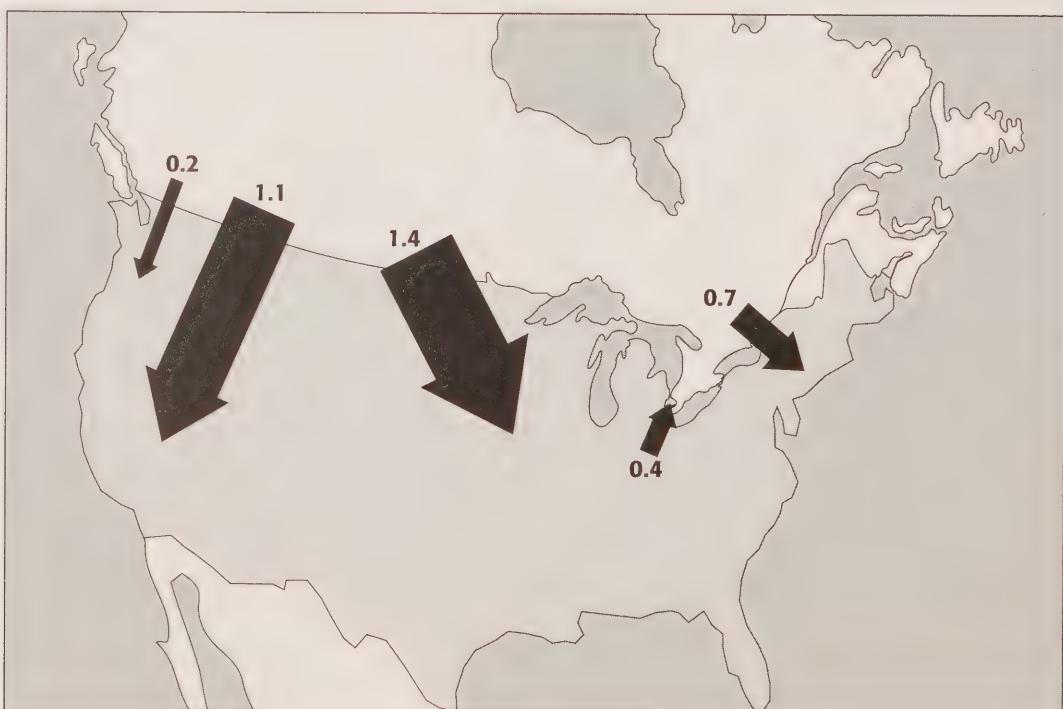
TABLE 6-31

Exports To Pacific Northwest – High Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	0.3	0.2	0.2	0.2	0.2
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.1	0.1	0.0
Low Cost Supply	0.0	0.0	0.0	0.0	0.0

TABLE 6-32

Ontario Industrial Burner Tip Prices – High Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	3.24	2.97	3.31	3.91	4.71
Ratios To Base Case					
High U.S. Demand	1.00	1.07	1.03	1.05	1.04
High Canadian Demand	1.00	1.08	1.04	1.06	1.05
Low Cost Supply	1.00	0.95	0.98	0.95	0.96
1992 EIA Control Case	1.09	1.40	1.55	1.53	1.49

TABLE 6-33

Québec Industrial Burner Tip Prices – High Technology
C$/GJ

	1993	1996	2001	2006	2011
Base Case	4.36	4.09	4.49	5.15	6.05
Ratios To Base Case					
High U.S. Demand	1.00	1.06	1.02	1.04	1.02
High Canadian Demand	1.00	1.06	1.03	1.05	1.03
Low Cost Supply	1.00	0.97	0.98	0.97	0.96
1992 EIA Control Case	1.07	1.29	1.41	1.41	1.37

TABLE 6-34

Canadian Demand – High Technology
Tcf/Yr

	1993	1996	2001	2006	2011
Base Case	2.3	2.5	2.9	3.3	3.8
Differences From Base Case					
High U.S. Demand	0.0	0.0	0.0	0.0	0.0
High Canadian Demand	0.0	0.1	0.1	0.1	0.1
Low Cost Supply	0.0	0.0	0.0	0.0	0.1
1992 EIA Control Case	0.2	0.3	0.0	-0.3	-0.9

both showing small decreases in two periods of the projection.

Exports in the High Demand case are particularly buoyant, causing an increase in Canadian burner tip prices. On the other hand, the Low Cost Supply results in lower exports making Canadian gas available for domestic consumption, especially after 2001, resulting in slightly lower burner tip prices in Ontario and Québec. On a regional basis the four major export markets for Canadian gas receive most of the increased exports until 2006. At that time, only California receives increased exports compared to the base case as HFO use is constrained in this region. In the Low Cost Supply case California and PNW maintain their level of Canadian gas throughout the projection; the decline in exports is in the Central and Northeast/Mid-Atlantic regions in the middle term of the projection.

The level of Canadian demand is affected in minor ways as a result of increased prices. Modest declines are seen in the higher priced cases and modest increases in the lower priced cases. Most of the changes occur in the industrial non-core sector.

Under the High Technology case, price fluctuations are less pronounced than the Current Technology case. In 2011, the range is $2.11 per gigajoule to $2.50 per gigajoule, between the highest and the lowest projections. Similarly, burner tip prices are lower than in the Current Technology case, with the range for Ontario being $4.50 to $4.92 per gigajoule and Quebec being $5.81 to $6.05.

Both major producing provinces are able to respond to the High U.S. Demand case, each increasing production in proportion. B.C. gains somewhat more when the High Canadian Demand is added. In the Low Cost Supply, Alberta production declines, but B.C. remains fairly constant.

In the High U.S. Demand case, export gains are indicated in the Northeast/Mid-Atlantic and to a lesser extent in the Central region. Both these regions show similar declines in the Low Cost Supply case. California and PNW are unaffected by either sensitivity case. As in the Current Technology cases, export capacity would have to increase to California and the Central region (Monchy and Emerson).

6.9.5   Export Impact Assessment Conclusions

Within each case the sensitivity analysis indicates a similar general trend although the effects are much more pronounced in the Current Technology cases. Fieldgate and burner tip prices respond as expected, being higher when demand is higher and lower when

supply is plentiful. The level of Canadian demand is affected in only minor ways in each of the sensitivity cases examined.

The Current Technology results indicate that Canadian production, and hence exports, can be expected to meet the higher demands until towards the end of the projection period. At that time consumers tend to substitute other fuels for gas. Exports and production in a situation of plentiful supply are adversely affected in the early part of the projection, but rebound towards the end.

In the High Technology cases, Canadian production responds to supply all of the increased demand, i.e., there is little fuel substitution. In the plentiful supply case, Canadian production and exports are lower throughout the projection. In this case, Alberta may lose about 15 percent of its production, but B.C. remains about the same.

As noted in Section 6.8 the required pace of drilling activity is quite high, especially in the Current Technology case. If the assumed High Demand case were realized, this would challenge the industry, perhaps to record levels in western Canada, or would advance the timing of some frontier or unconventional gas projects.

In general, the effects of the sensitivities on the key indicators are not particularly large but could be regarded by some as important. Given the length of the period over which these effects occur, both the up-stream industry and the consuming sector appear to be able to make the necessary adjustments to respond to the supply and demand conditions.

It is recognized that great uncertainty surrounds projections of this type given that there are many possible future outcomes.

6.10   CONCLUDING COMMENTS

Our view of the resource base indicates that there is sufficient natural gas in the WCSB to meet the projected demand for both domestic consumption and exports. It is also apparent that only modest supplies are required from the east coast frontier region and none from the northern region within the projection period. Further, it is unlikely that Canadian coalbed methane will be a substantial supply source in this time frame.

Technology may have a substantial impact on supply costs and consequently prices at both the well head and burner tip. In the High Technology case prices are $2.00 per gigajoule less than the Current Technology assumptions by the end of the projection. However there appears to be a limiting effect on Canadian production

due to the high proportion of exports (about 50 percent of all production is exported) in the High technology case. This is due to competition from U.S. gas that has lower supply costs until about 2000, after which Canadian exports, and hence production begin to expand fairly rapidly. In the Current Technology case gas begins to lose market share to HFO after 2005 due to the relatively high price of gas under those assumptions. Under both views of technology exports reach about the same level (approximately 3 Tcf) by the end of the projection and production is of the order of 6 Tcf annually. Canadian imports could reach 0.4 Tcf by the end of the forecast, but are unlikely to be sustained at that level. Production in 1993 was 4.2 Tcf, exports were 2.2 Tcf and imports were less 0.1 Tcf.

The sensitivity cases examined indicate that increased demand is unlikely to be completely satisfied by natural gas over the long-term, under the Current Technology assumptions, as gas loses market share to other fuels because of its higher price. On the other hand this higher demand is met, with relatively modest price increases in Canada under the High Technology assumptions. Should additional supplies be introduced to the market there is likely to be a medium-term drop in both Canadian production and exports, under both technology assumptions; this effect is more prominent in High Technology case. In the longer term exports and production do recover, but prices are depressed by about 10 percent.

Productive capacity appears to be adequate to meet market demands although the level of drilling required in the WCSB is substantially higher than recent years, but only slightly higher than that recorded in the early 1980s. This applies to both cases; however it occurs a little later in the High Technology case. B.C. increases its share of productive capacity over the projection due to the increase in resource estimates and reduced supply cost estimates for that province. As noted above there is little call on frontier or unconventional gas in this projection. However, this may change if the productive capacity from reserves additions or unconnected gas pools does not evolve according to our assumptions. The Board expects to release a study of unconnected gas pools in central Alberta, which suggests a substantial reduction in these reserves for this region. If the results are generally applicable to the WCSB it may have an impact on overall productive capacity and may understate the estimated level of drilling.

It is apparent that intra-provincial pipeline systems, domestic mainlines and export pipelines will all need to be expanded in order for larger volumes of gas to reach the market place. This is particularly true for exports to California and the U.S. Mid-west. Also of note would be the addition of capacity to handle projected increasing B.C. gas to flow to eastern markets.

The Export Impact Assessment indicates that both domestic and export requirements can be met under both technology cases and the three sensitivities analyzed, although, the High U.S. Demand will likely cause drilling levels well in excess of those previously achieved.

Compared to the 1991 Control case we have generally projected higher production and exports and generally lower prices in this report. This primarily due to the re-assessment of the supply costs in both Canada and U.S. as well as lower oil prices and a lower backstop resource cost.

Chapter 7

CRUDE OIL AND EQUIVALENT

7.1   INTRODUCTION

7.1.1   Outline

This chapter focuses on supply of crude oil and equivalent and on the balances between projected oil supply and demand. Figure 7-1 provides a framework for this discussion and can be used as a "road map" for the chapter. Canada's oil resources, through production from established reserves and reserves additions,

contribute to the supply of crude oil and equivalent in both the domestic and export markets. Domestic oil supply, combined with imported crude oil, satisfies the requirements of Canadian refineries and, indirectly, domestic demand for refined products, after taking account of imports and exports of products to balance refinery operations.

In our analysis, we consider four major crude oil supply categories: conventional light oil in the Western

FIGURE 7-1
Crude Oil Supply/Demand
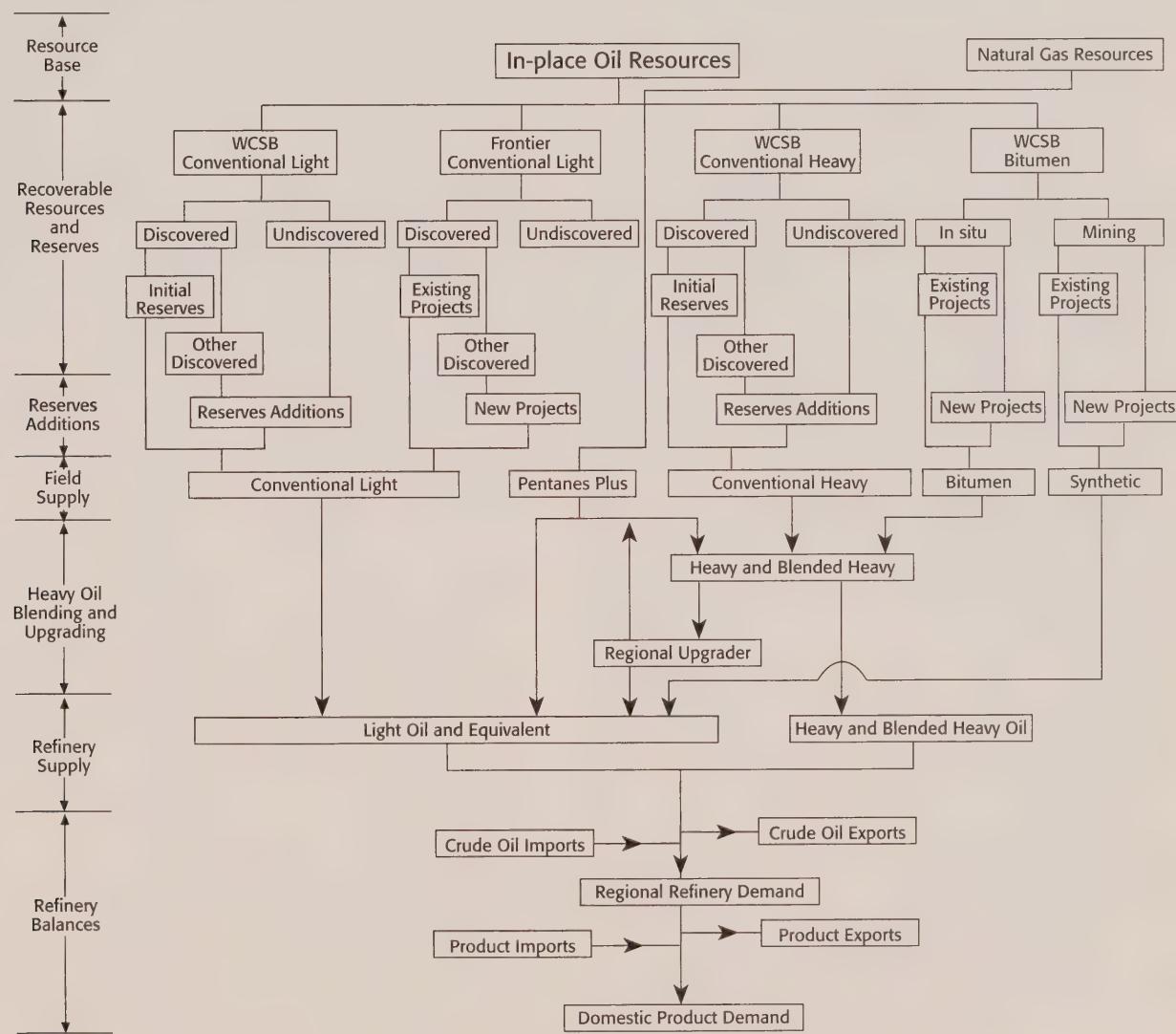
Canada Sedimentary Basin (WCSB); conventional heavy oil in the WCSB; conventional light oil in the frontier regions; and bitumen from Alberta oilsands. For each of these categories, we review the resource base underlying our supply projections, the supply costs for projects using presently available and emerging technologies, projected reserves additions, and expected productive capacities. The individual components of the field supply are reconstituted as supply of light and blended heavy oil available to the end-users by taking into account blending and upgrading. Projected supply is then compared with expected demand to assess the overall supply/demand balance. The final part of the chapter comments on the implications of the projections for Canada's oil self-sufficiency and adequacy of oil pipeline capacity.

Before discussing the four major categories of crude oil supply, we first make some general comments on the following: alternative scenarios; oil prices and uncertainty; resource base and uncertainty; recent impact of new technologies; and supply cost methodology.

7.1.2 Alternative Supply Cases

Crude oil prices have traditionally been considered a key factor driving Canadian oil supply. Consequently, alternative oil supply scenarios, including those by the NEB, have generally been based on assumptions about future oil prices. In recent years, oil prices have declined, leading to a general lowering of price expectations. There is little agreement on the future outlook for oil prices among analysts (Chapter 3). However, there is little doubt that technology will have an impact on oil supply costs and hence prices. Recent technological advances have succeeded in lowering these costs by up to one-quarter since 1990. The trend is expected to continue, as oil producers strive to reduce costs in an environment of low oil prices.

This fundamental shift in price expectations is reflected in our analysis which uses technological progress, rather than oil prices, as a focal point for oil supply projections. The impact of technology is illustrated with two alternative oil supply cases. The **Current Technology case** (Current Tech) uses supply costs associated with technologies that are currently commercial, or extensively piloted and close to becoming commercial. The **High Technology case** (High Tech), by contrast, utilizes supply costs associated with technologies that are in the early stages of development. These cost estimates are based on the analysis of historical trends, consultations with the industry, and our judgement. In our analysis,

technological progress is measured by its impact on supply costs.

7.1.3 Oil Prices and Uncertainty

In order to isolate the impact of technology on future Canadian crude oil supply, both the Current Tech and High Tech cases use the same oil prices. World oil prices, as represented by WTI prices at Cushing, are projected to increase gradually from US$19 per barrel in 1993 to US$23 in 2010. Future prices may fluctuate widely around this trend, depending on supply/demand considerations and the degree of price control exercised by OPEC. To provide notionally some consistency with the natural gas analysis, the two oil cases have used gas prices projected in the corresponding Current Tech and High Tech gas supply cases.[1] All prices and supply costs quoted in this chapter are in constant 1993 dollars.

Canadian wellhead prices for particular supply sources and locations are shown in Table A7-1. These prices are derived from projected WTI prices at Chicago using appropriate transportation costs and quality differentials, and an exchange rate of US$0.79 per $1.00. Wellhead prices for conventional crude oil in the WCSB are based on a constant, $1.71 per barrel, IPL toll from Edmonton to Chicago and on a gathering cost of $1.27 per barrel from the field to Edmonton. This charge is somewhat higher than the current average gathering cost, reflecting higher transportation costs associated with trucking or with new feeder lines required to tie-in new discoveries. As a result of these adjustments, the US$19-23 range for WTI prices at Cushing translates into a $21.75-26.75 range for equivalent Alberta light crude oil at the wellhead. Wellhead prices for offshore East Coast production are estimated at US$1.25 per barrel below WTI prices at Chicago. This differential reflects an average shipping cost to an East Coast port and the price difference between that port and Chicago.

Despite relatively stable oil prices since 1991, **price uncertainty** continues to linger and has to be accounted for in producers' development plans. The late-1990 price increase to US$40 per barrel (triggered by the Persian Gulf crisis) and the late-1993 price decline to US$14 (due to sluggish demand, increases in non-OPEC supply

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1 The Current Tech case for oil is analogous to the Current Tech case for natural gas. The High Tech assumptions for oil supply differ from those for gas, in that the oil technology improvements are associated with specific developments, such as horizontal drilling, whereas in the High Tech improvements related to gas, we have assumed that proportionately lower supply costs for gas will result from unspecified technological progress.

and overproduction by OPEC) are indicative of the amplitude of possible future price fluctuations. For our long-term price projections, we have defined lower and upper bounds of US$15 and US$30, respectively, for reasons described in Chapter 3. The two bounds are used to measure the price sensitivity of future oil supply in the Current Tech case.

The selection of the Current Tech case for price sensitivity analysis does not, in any way, imply that this case is more likely than the High Tech case. To the contrary, it is more realistic to expect that technological progress will continue, at least at a modest rate, than to expect that it will largely cease. Furthermore, the low price sensitivity for the Current Tech case does not imply that technological progress will cease at the US$15 price.

Given that supply costs in the Persian Gulf are very low, a price near or even below the bottom end of our sustainable range would be likely if OPEC failed to act cohesively. Significant OPEC cooperation would be required to maintain even the mid-range price track. The

top end of the range, US$30, is included in the sensitivity to reflect the view that OPEC could set a higher price if the supply costs of non-OPEC producers were higher than assumed in our analysis. In particular, the full-cycle supply costs in the U.S. and Canada are estimated to generally range between US$20 and US$30.

7.1.4   Resource Base and Uncertainty

The crude oil resource base encompasses all in place volumes of crude oil, conventional as well as unconventional. For the purpose of this analysis, we focus on that part of the resource base which is estimated, at this point, to be ultimately recoverable using current technology. Since future crude oil supply will be obtained from this resource, its size, geographical location and other characteristics are important considerations with respect to the supply projections. The locations of major Canadian crude oil supply sources are depicted in Figure 7-2.

FIGURE 7-2
Crude Oil Supply Sources
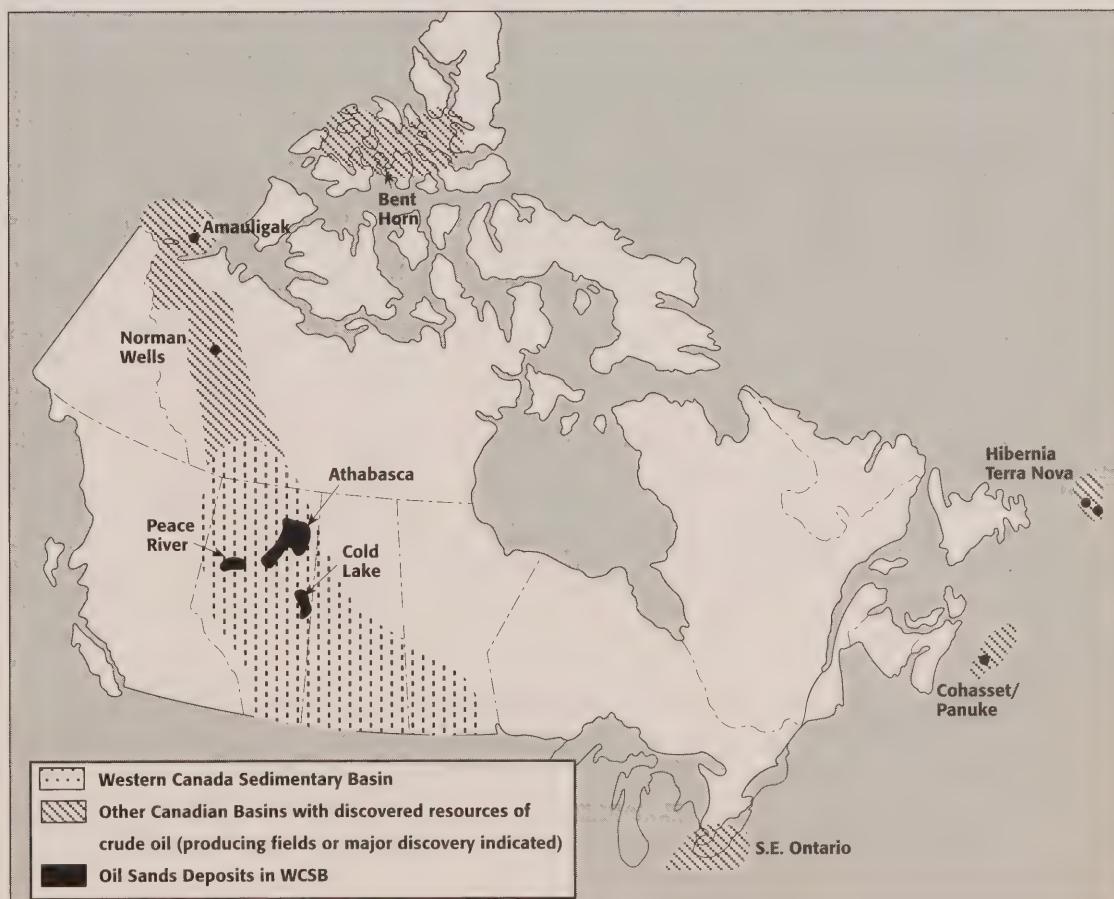
The estimates of ultimate recoverable resources are as of year-end 1992, and are broadly divided into discovered and undiscovered resources. These are revised from year to year as production continues, new discoveries are made, other discovered resources are converted to reserves, and our overall understanding of the size and characteristics of resources improves. The recoverable resource components in this analytical framework are illustrated in Figure 7-1.

Discovered recoverable resources are those that are estimated at this time to be recoverable from known accumulations (that is, accumulations which have been proven by drilling, testing or production) using known technology. Included in this category are: cumulative production, remaining established reserves and other discovered recoverable resources. Established reserves are that part of the discovered recoverable resource base that is estimated to be economically recoverable using known technology (described in "Recovery Methods" inset) under present and anticipated economic conditions. Those established reserves not yet produced are termed remaining established reserves. Initial established reserves are the sum of remaining established reserves and cumulative production.

Other discovered recoverable resources are those resources that are currently estimated to be recoverable using known technology but which have not yet been recognized as established reserves because of uncertain economic viability. Conventional crude oil resources in this category are comprised of crude oil volumes associated with possible future improved recovery projects in currently established conventional light and heavy crude oil pools, and of discovered recoverable resources in frontier regions which have not yet been recognized as established reserves. These resources will require price increases and/or reductions in development costs through technological advances to be commercially developed.

Undiscovered recoverable resources are those that are estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but have not yet been shown to exist by drilling, testing or production. The estimates of recoverable oil are based on the application of known technologies. Estimates of undiscovered resources are sometimes expressed as ranges with associated probabilities of occurrence. When so expressed, we have used the "average expectation", implying that actual reserves are just as likely to be higher as lower than our estimate. Both extensions to currently established pools and new

discoveries are included in this category. In our estimates we have focused on conventional crude oil, as the undiscovered recoverable bitumen resource is not believed to be significant enough to affect our supply projections.

Conventional crude oil resources are categorized as light or heavy crude oil based primarily on oil density and viscosity, but also taking into account the ultimate market utilization. Our crude oil classifications are generally the same as those of the provincial agencies, except that our light category encompasses all of Alberta's light and medium category, and our heavy category includes all of Saskatchewan's medium classification.

The conventional crude oil resource base is estimated to consist of about 30 billion cubic metres of original oil-in-place, of which only about 8.6 billion cubic metres (28 percent) are currently estimated to be ultimately recoverable (see Table 7-1). Of this, some 7.4 billion cubic metres are categorized as light crude oil and about 1.1 billion cubic metres are categorized as heavy crude oil. For light crude oil, 3.2 billion cubic metres are estimated to exist in the WCSB and 4.2 billion cubic metres in frontier basins (in northern Canada and offshore). All of the recoverable heavy crude oil, by contrast, is located in the WCSB.

Unconventional crude oil resources differ from conventional resources in that they are more difficult to recover because crude oil in this category generally does not flow into a wellbore and cannot be shipped to a refinery without significant processing or preparation. Canada's largest unconventional oil resource is bitumen, found in large oilsands and carbonate deposits in Alberta. Although there are other possible sources of unconventional oil, such as oil shales and coal, these sources are not likely to contribute to supply in the foreseeable future and are, therefore, disregarded in our analysis.

The in-place resource of bitumen consists of approximately 400 billion cubic metres, of which 49 billion cubic metres (about 12 percent) are estimated to be ultimately recoverable. Additional undiscovered resources may exist, but these are not expected to be significant in relation to the discovered resources. All of the bitumen is contained in three large areas in northern Alberta defined by the ERCB as Athabasca, Cold Lake and Peace River. The very large Athabasca area, located 400 km north of Edmonton, contains the most viscous bitumen of the three oil sand areas. It was the first to be exploited because some 24 billion cubic metres of bitumen in-place is sufficiently shallow for

TABLE 7-1

Crude Oil and Bitumen Resource Estimates at Year End 1992

(millions of cubic metres)

| | Cumulative Production | Discovered Recoverable Resources | | | Undiscovered Recoverable Resources | Ultimate Recoverable Resources | Original Oil In Place |
		Remaining Established Reserves	Other Discovered Resources	Total			
Conventional Crude Oil							
Light							
British Columbia	77	19	18	114	21	135	344
Alberta	1 705	343	334	2 381	451	2 832	8 380
Saskatchewan	144	31	40	216	40	255	1239
Manitoba	29	7	3	39	8	47	177
Subtotal – WCSB	**1 955**	**400**	**395**	**2 750**	**519**	**3 269**	**10 140**
Ontario	11	2	0	12	0	12	41
Nova Scotia Offshore	1	5	3	8	104	112	375
Newfoundland Grand Banks	0	98	145	243	507	750	2 500
Mainland NWT and Yukon[1]	18	20	2	40	55	95	315
Mackenzie Delta & Beaufort Sea	0	0	223	223	905	1 128	3 760
Arctic Islands	0	1	65	66	686	752	2 910
Other frontier basins[2]	0	0	0	0	1 325	1 325	4 417
Subtotal – Frontier	**19**	**123**	**438**	**580**	**3 582**	**4 162**	**14 276**
Subtotal – Light	**1 984**	**525**	**833**	**3 342**	**4 101**	**7 443**	**24 457**
Heavy							
Alberta	146	69	138	353	99	451	2 204
Saskatchewan	264	86	162	512	161	673	3 706
Subtotal – Heavy	**410**	**155**	**300**	**865**	**260**	**1 125**	**5 910**
Total – Conventional	**2 394**	**680**	**1 133**	**4 207**	**4 361**	**8 568**	**30 367**
Bitumen							
Mining Projects	210	434	9 356	10 000	0	10 000	24 000
In Situ Projects	59	48	38 893	39 000	0	39 000	376 000
Total – Bitumen	**269**	**482**	**48 249**	**49 000**	**0**	**49 000**	**400 000**

Notes:
1   Under review by the Geological Survey of Canada.
2   Resource estimates for prospective regions which lack confirming discoveries have been aggregated. These regions include the Georges Bank and Laurentian sub-basin, East Newfoundland Basin and southern Grand Banks, the St. Lawrence lowlands and Maritimes basin, Hudson Bay, eastern Arctic offshore and the Queen Charlotte Basin.
    Numbers may not add due to rounding.

Sources:
    Appendix Table A7-2 for estimates of conventional resources in Western Canada.
    Geological Survey of Canada for estimates of Ultimate Recoverable Resources in frontier regions.
    Offshore Petroleum Boards for estimates of reserves and resources of the east coast offshore.
    NEB for estimates of reserves and resources in the Mainland Territories, Mackenzie Delta – Beaufort Sea, Arctic Islands and eastern Arctic offshore.
    Alberta ERCB Report ST93-18 for estimates of bitumen resources.

surface mining. Surface mining is an effective recovery mechanism that could potentially recover up to 40 percent of the original oil-in-place of 24 billion cubic metres in the mineable deposits. This compares with about 10 percent recovery for the remaining 376 billion cubic metres contained in deposits not amenable to surface mining.[1]

It should be noted that the estimates of crude oil resources in place are subject to considerable **uncertainty**, as they reflect the prevailing geological understanding. The magnitudes of discovered resources are known with more certainty than the estimates of undiscovered resources (particularly those the frontier basins). The latter estimates are highly uncertain and can be expected to have a wide range, although this range will narrow as geological knowledge is accumulated through ongoing exploration.

The degree of uncertainty of the in-place resource estimates for the WCSB is probably less for oil than for gas, due to: (a) a greater maturity of exploration for oil in the basin and correspondingly larger knowledge base; and (b) the generally shallower depth of oil pools (oil formation is constrained to narrower temperature and pressure ranges than the formation of natural gas).

Estimates of recoverable resources are subject to considerable change because they are influenced by prevailing technology and energy prices. This phenomenon is expressed in the "resource triangle" theory (see Chapter 6).

The basic concepts of the "resource triangle" theory apply equally to crude oil and natural gas, but the practical implications for recoverable resource estimates are somewhat different. In contrast to resources in place, estimates of recoverable resources are more subject to change for crude oil than for natural gas for two reasons. Firstly, the physical properties of crude oil vary over a wider range which leads to more diverse recovery factors for different crude oil types. Secondly, average recovery factors for oil are currently about one third of those for gas. Consequently, since the recovery factors are primarily determined by available technology, the rate of technological progress for recovery processes may have a greater bearing on estimates of discovered resources for oil than on those for gas.

In summary, the total Canadian crude oil resource in place is very large due, primarily, to the large bitumen component. When a resource is sufficiently large, its size poses no constraints on development over the projection period. For example, our supply projections for bitumen assume that oilsands developments will be driven mainly by economic considerations, and will not be constrained by the available resource. The projections for conventional light and heavy oil, by contrast, reflect a more mature stage of development. The recent gains in Canadian oil supply relate to reductions in costs and improvements in recovery factors, and not to upward revisions of estimated in-place resources. The estimates of recoverable resources are imprecise and generally increase with technological advances in recovery processes and with improved geological knowledge. Our estimates of recoverable resources listed in Table 7-1 are based upon current technology (Current Tech case). We have attempted to illustrate the impact of technological progress by considering the High Tech case. Although we have not assessed the recoverable resources for this case, our analysis imply that they will be larger because expected superior extraction technologies will result in higher recovery factors.

7.1.5   Recent Production and Impact of New Technologies

Contrary to the previous NEB and industry forecasts, which foresaw gradually declining production rates, production of conventional light and heavy oil in the WCSB has increased over the past few years. Conventional heavy oil production performed particularly well, registering an average annual gain in production of around 4 thousand cubic metres per day between 1990 and 1993, and reaching 61.5 thousand cubic metres per day in 1993. Conventional light crude oil production was essentially constant over the same time period, averaging around 140 thousand cubic metres per day.

Frontier crude oil supply originates from established operations at Norman Wells (approximately 5 000 cubic metres per day), Bent Horn (57 000 cubic metres in one or two summer shipments per year, equivalent to 160 cubic metres per day), and the Cohasset/Panuke project. The Panuke field came on stream in June 1992 as scheduled, producing 2 000 cubic metres per day of very light crude oil. The Cohasset field began production in the summer of 1993, bringing productive capacity to nearly 6 000 cubic metres per day.

In other crude oil and equivalent categories, supply of synthetic oil has also been higher than generally expected, increasing to 38.9 thousand cubic metres per day in 1993. This was due mainly to continued

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1   The recovery factors for individual projects may be substantially higher than these average factors.

debottlenecking at the Syncrude plant. Supply of pentanes plus registered a healthy gain to 23.8 thousand cubic metres per day in 1993, as a result of further increases in natural gas production, while bitumen supply edged up marginally to 21.4 thousand cubic metres per day in 1993.

In the absence of any oil price increases since 1990, this strong production performance can be attributed mainly to cost reductions achieved through the industry's rationalization efforts and technological progress. This progress has resulted in major improvements in such areas as: horizontal well technology, geophysics (i.e., 3-D seismic), remote sensing, petrophysics, drilling equipment, production equipment (i.e., progressive cavity pumps, coiled tubing, slim hole and continuous sucker rod) and recovery technologies (i.e., better modelling for optimizing recovery).

Of these technological developments, the advent of the wide spread use of **horizontal drilling** has probably had the greatest effect on conventional crude oil supply. In a horizontal well, the reservoir contact is substantially increased by deviating the lower section of a vertical well and drilling horizontally within the pay zone. This often leads to accelerated

Horizontal Drilling Trend

The number of horizontal wells in Western Canada has increased exponentially over the last several years, as illustrated in Figure 7-3. Horizontal drilling was first applied in Canada in 1978 by Esso Resources Canada Ltd. in the Cold Lake Clearwater A oilsands deposit in Alberta. This was followed by horizontal wells drilled in the Norman Wells, Rainbow and Suffield areas. Saskatchewan's first horizontal well was completed in the Tangleflags heavy oil pool in conjunction with a steam flood project. In 1987, only six horizontal wells were drilled in the WCSB. This number increased subsequently to 17 wells in 1988 and 881 in 1993.

The popularity of horizontal wells stems from improved profitability, derived from accelerated production profiles (higher initial rates and steeper declines), increased overall production per well, and royalty incentives (particularly in Saskatchewan). These advantages more than offset the higher costs of drilling horizontal wells compared to vertical wells. With rapid technological improvements, the cost ratio between the horizontal and vertical wells has been falling steadily. At present, a typical horizontal well costs somewhat less than two corresponding vertical wells, while a horizontal re-entry costs approximately the same as a new vertical well.

The technology has already proven to be very versatile and applicable to various geological formations, reservoir conditions, oil types and methods of recovery. Horizontal wells can be drilled in many different ways: from surface locations, underground tunnels and existing vertical and horizontal wells. Formations have been targeted for infill well development or for full field development in both carbonate and sandstone reservoirs. In Alberta, horizontal wells have been used to drain portions of oil reservoirs where previous use of vertical wells caused severe gas and/or water coning, negatively affecting overall recovery.

FIGURE 7-3
Horizontal Drilling in the WCSB

number of wells

Cumulative Total to end 1993 = 1,670
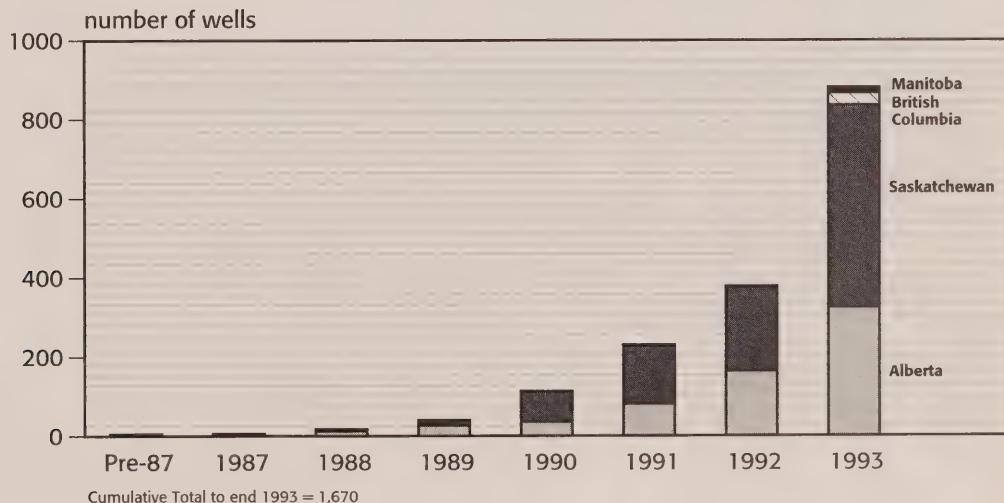
production and higher recovery than found in corresponding vertical wells. A review of the producing well count (see "Horizontal Drilling Trend" inset) and production statistics for late 1993 shows that horizontal wells represented only 2.4 percent of the total producing well count, but accounted for 9.0 percent (about 17,800 cubic metres per day) of total conventional oil production from the WCSB.

Horizontal drilling techniques have been applied in conjunction with technological advances in areas such as:

- drilling fluids and under-balanced drilling to minimize formation damage;

- down-hole motors to facilitate short-radius deviation;

- specialized down-hole tools for horizontal drilling;

- drill rig innovations (top drive);

- drill bit design;

- measurement-while-drilling tools, especially the capability to locate and guide the drill bit within the target formation; and

- completion practices.

With regards to **offshore oil technologies**, progress is being made in areas of extended-reach drilling, sea-floor completions and production platforms. As a result of this progress, and programs such as the United Kingdom's "Cost Reduction Initiative for the New Era",[3] development costs in the North Sea are expected to continue to decrease by up to 30 percent over the next few years. Some of these technologies may be adopted to develop oil resources located offshore Newfoundland and Nova Scotia.

Oilsands technologies associated with extraction, separation and upgrading of bitumen have been another area of impressive technological progress. Some of the most promising processes that are now being tested include: Steam Assisted Gravity Drainage (SAGD), Vaporized Extraction (VAPEX), AOSTRA Taciuk Process (ATP), Bitmin's Counter-Current Drum Separation (CCDS), Hydrotransport, as well as CanOxy's Sand Reduction Technology (SRT), and Direct Upgrading Technology (DUT). Technical aspects of these processes and their advantages are described in "New Oilsands Technologies" inset in section 7.5.2.

These technological developments have already resulted, or may soon result in substantial reductions in oil supply costs. The methodology for calculating these costs is provided below.

7.1.6 Supply Cost Methodology

The economic viability of crude oil projects is evaluated for various technologies using the concept of **supply cost** which expresses some or all costs associated with resource exploitation as an average cost per unit of production. The main cost components are: capital costs associated with exploration (e.g., geological and geophysical surveys and exploration drilling) and development (e.g., development drilling and surface facilities), production operating costs, federal and provincial taxes, resource royalties and minimum required return.

Depending on the nature of a project, capital costs can include both exploration and development expenditures (full-cycle costs), or only development expenditures (half-cycle costs). Operating costs typically comprise two components: a fixed cost per well per month and a variable cost per unit of output. Taxes and royalties used in the calculations are those in effect in respective jurisdictions as of January 1993. Finally, the minimum required return is calculated at eight percent based on the average long-term after-tax cost of capital (see "Discount Rate Calculation" inset for derivation).

The project-specific supply costs were calculated using the Petroleum Economic Evaluation Program (PEEP) developed by Merak Projects Ltd. This cash flow model compares the discounted revenue and cost streams over the lives of the projects to calculate such economic indicators as: net present value, rate of return, payout period and unit supply cost. The main inputs required by PEEP are: production profiles, capital and operating costs, tax and royalty information (i.e., related to location, status of projects, type of resource), risk factor (i.e., probability of success) and assumed discount rate.

As a notable departure from the previously used methodology, two price-sensitive components of the supply costs – taxes and royalties – are now calculated independently of the price forecasts. This is achieved by calculating taxes and royalties based on estimated supply costs in an iterative process that leads to a convergence of the present values of revenue and cost streams. The levelized price at which the two values become equal is displayed as the supply cost. In order to accurately assess taxes and royalties, PEEP inflates all cost components at the assumed inflation rates, performs cash flow calculations and deflates the results to provide

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3   This program was discussed in *Oil and Energy Trends*, January 21, 1994, p.17.

supply costs in constant dollars. If a project also produces by-products, such as natural gas liquids, associated revenue is used to reduce the cost in proportion to the ratio of by-product price to the calculated oil or gas supply cost.

Supply costs are compared to projected oil prices in order to assess the projects' economic viability and likely start-up dates. When these costs are lower than projected prices, projects are deemed commercially viable. For presently uneconomic projects that do not have any development plans, projected timing is generally based on the assumption that projects come on stream when prices become equal to supply costs. This implies that investors have reasonable confidence in the projected price path, and sufficient foresight to commence development prior to the time when prices reach supply costs. This assumption is, in certain cases, modified to reflect such considerations as: possible conflicts with other major projects regarding manpower and financing, government incentives and varying degrees of risk involved. Oilsands and marginal heavy oil projects are prime examples of such exceptional cases. High capital and operating costs associated with these projects, and their vulnerability to oil price

fluctuations, sometimes justify delaying projected start-ups beyond the time dictated by the comparison of prices with supply costs.

For the Current Tech case, supply costs are estimated for technologies that are presently commercial or close to becoming commercial. For example, conventional horizontal wells are considered to be presently commercial, while the SAGD process is close to becoming commercial in oilsands applications. For the High Tech case, supply costs are estimated for the most promising emerging technologies such as: horizontal re-entry and multiple leg wells, ATP, CCDS, Hydrotransport, SRT and DUT. These cost estimates are based on research done to date, and are generally more speculative. Where future direction of technological progress is uncertain, we have assumed gradual cost reductions in the range of 1 to 2 percent annually. These reductions are related to both the improvements in existing technologies and the development of new unspecified technologies.

Our estimates of supply costs are discussed individually for the four supply components in the respective sections. It is important to note that the approaches used for the calculation of supply costs were

Discount Rate Calculation

The underlying assumptions for the discount rate determination are:

Inflation	2.20%	see Macro-economic assumptions
Risk free cost of debt	7.75%	Canada 30-year 7.49%, 10-year 7.25%, "Consensus Forecasts, A Digest of International Economic Forecasts, August 1993", adjusted for slightly higher inflation in NEB assumptions
Oil Co. cost of debt	9.50%	1.75% premium for corporate bonds
Market risk premium	5.00%	Expert testimony at Hearings
Beta for oil and gas	1.20	Powerwest, Canadian Upstream Oil and Gas Profitability, Sept. 1991, p.83. This gives a market premium of 6% (5 x 1.2) for oil and gas companies over the risk free rate.
Cost of Equity	13.75%	7.75 plus 6.00%
Average equity portion	60.00%	Powerwest, Canadian Upstream Oil and Gas Profitability, Sept. 1991, p.82.
Tax rate	45.00%	

The Weighted Average Cost of Capital = E * R + (1− E) * I * (1 − T)

Where:			
	R	Equity Rate of Return	13.75 percent
	I	Interest Rate	9.50 percent
	E	Portion of Equity	60.00 percent
	T	Tax Rate	45.00 percent

Using this formula, the weighted average cost of capital calculates to 10.34 percent in nominal terms or about 8.0 percent in real terms, after accounting for inflation.

different for conventional oil in the WCSB as compared to frontier and unconventional oil. For conventional oil in the WCSB, supply costs of exploratory drilling prospects are based on an aggregate assessment of the full-cycle costs of incremental supply. These costs are summarized in a supply cost curve which relates incremental reserves to supply costs. For the other two categories, supply costs are half-cycle and are estimated on an individual project basis using information obtained from the operators.

Over the projection period, a portion of "other discovered resources" and "undiscovered resources" will be added to reserves and can be expected to contribute to crude oil supply. The extent to which these reserves additions can be anticipated to occur is determined by the characteristics of the resource, technology, and economic factors. The levels of reserves additions are determined by comparing the supply costs for available technologies with projected oil prices. The time at which a specific development proceeds, or the rate at which exploration in general proceeds, depends mainly upon perceived profitability.

7.2   CONVENTIONAL LIGHT OIL – WCSB

This section discusses the recoverable resources, supply costs and reserves additions, and projected field supply for conventional light crude oil in the WCSB. The orientation of these aspects within the overall analytical framework is illustrated by the diagram in Figure 7-1, and the resource numbers stated below are summarized in Table 7-1.

7.2.1   Resources

For conventional light crude oil, about 2.75 billion cubic metres, or about 84 percent of the estimated ultimate **recoverable resource potential** of 3.27 billion cubic metres, has been discovered. Initial established reserves as of year-end 1992 amount to 2.35 billion cubic metres, including 1.95 billion cubic metres that had already been produced. Other discovered resources and undiscovered resources are estimated at 0.4 and 0.5 billion cubic metres respectively. It is interesting to note that the estimate of undiscovered resources is only 25 percent higher than that of remaining established reserves.

Estimates of **initial established reserves** of conventional light oil are compiled from assessments of individual pools by Board staff, industry studies and estimates from provincial agencies. These estimates are generally based on the assumption that current production operations will be continued and are shown by province and by pipeline system in Table A7-6.

Growth of initial established reserves of conventional light crude oil results from exploration and development drilling, as well as from higher recovery achieved through improved oil recovery (IOR) techniques, well workovers and stimulation. Between 1980 and 1985, the rate of growth of initial established reserves was relatively constant, averaging approximately 50 million cubic metres per year. The 1986 oil price collapse resulted in reduced activity and correspondingly lower levels of reserves additions through 1990 (Figure 7-4). The improvement in oil-directed drilling activity rates, plus increased levels of infill drilling due to the application of horizontal drilling

FIGURE 7-4

Established Reserves of Conventional Light Oil – WCSB

Source: Appendix Table A7-3
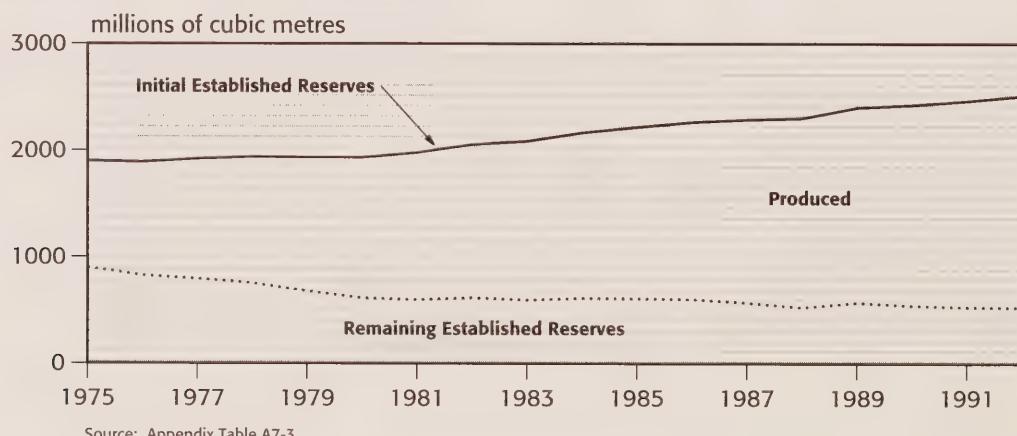
technology, led to higher levels of reserves additions for 1991 and 1992.

A comparison of estimates of initial established reserves with those contained in the NEB's 1991 report indicates that, in the three-year period since year-end 1989, initial established reserves have increased by 85 million cubic metres. Approximately 40 percent of this increase can be attributed to new discoveries, extensions to existing pools, and infill wells. In Alberta, a considerable number of horizontal wells were completed in the areas of: Peace River Arch, Provost/Halkirk/Killam, Valhalla, and Gilby/Medicine River/Sylvan Lake. Another 45 percent is due to the installation of increased water handling capability, recompletions, stimulation, and other production enhancement techniques. The remaining 15 percent is attributable to the initiation or expansion of IOR projects, primarily waterfloods, located in pools throughout the WCSB.

On average, primary recovery techniques are expected to recover 19.5 percent of the in-place conventional light oil. Improved recovery brings the expected overall recovery factor to 28.2 percent. Average recovery factors vary significantly by province, from 17.2 percent in Saskatchewan to 29.6 percent in Alberta and 33.9 percent in B.C. (derived from Table A7-2). This variation is caused by differences in geological characteristics, reservoir quality, viscosity of crude oil, recovery mechanisms and the extent to which improved recovery schemes have been implemented.

Historically, average recovery factors have tended to increase due to gradual improvements in recovery techniques ("Recovery Methods" inset for details). For instance, between 1989 and 1992 the recovery factors have increased from 27.5 to 28.2 percent due mainly to the impact of horizontal drilling. Temporary reversals of this trend during the 1980s were due to the discovery of lower-quality resource accumulations.

Cumulative production amounts to 71 percent of the recoverable resource discovered to date.

The **remaining established reserves** are estimated as of 31 December 1992 to be 400 million cubic metres, compared to the 31 December 1989 estimate of 463 million cubic metres quoted in our 1991 Report (Table A7-3 for historical data). Nearly 94 percent of this decline was in Alberta. Figure 7-4 shows that remaining established reserves declined from a peak of about 1,540

Recovery Methods

Primary recovery methods employ only the natural energy of the reservoir for production of crude oil. Recovery for this method can be maximized through prudent production practises and reduced well spacing which is now generally recognized as an important consideration in optimizing oil recovery. The more advanced recovery techniques, which typically employ fluid injection to maintain reservoir pressure and to mobilize the crude oil, are commonly described as secondary and tertiary recovery processes. Implementation of such improved recovery techniques in producing pools is frequently conducted in conjunction with infill drilling programs to maximize oil recovery.

In accordance with current industry terminology, we use the term "improved oil recovery" (IOR) to refer to all increases in oil recovery resulting from infill drilling, horizontal wells, waterflooding, gas floods, miscible floods, steam floods and other enhanced recovery techniques.

Although the benefits of waterflooding (the injection of water to displace oil from the reservoir) became generally recognized in the early 1950's, it is still the most common fluid injection method employed to improve recovery, in both light and heavy crude oil reservoirs. Apart from waterflooding, the most common fluid injection recovery technique for light oil uses solvent miscible with oil under reservoir conditions. In Canada, this solvent is usually some combination of methane, ethane, propane, and possibly smaller amounts of butanes and pentanes plus. Carbon dioxide can also be used as a miscible fluid but has been applied only on a limited scale in Canada.

For conventional heavy oil, the second most common improved recovery technique after waterflooding is steam injection. An alternative thermal technique is in situ combustion. This technique involves burning part of the oil in the reservoir through air or oxygen injection to produce heat. Other more costly and more specialized processes such as surfactant, alkaline or polymer-assisted waterfloods are available for use in both light and heavy crude oil reservoirs. However, these are expected to provide only minor volumes of incremental recovery over the projection period.

Great strides have been made in the last five years in the development and application of horizontal well technology, which involves drilling of a section of a wellbore parallel to and within the producing formation, thereby creating much greater contact area with the reservoir and commonly resulting in accelerated production rates and improved recovery. Horizontal infill wells are being widely employed in conjunction with existing waterflood, steamflood and miscible flood projects as well as in some primary recovery projects. Some heavy oil pools have been developed entirely with horizontal wells. It is expected that horizontal wells in combination with other recovery processes will be the dominant improved recovery method over the projection period.

million cubic metres in 1969 to about 580 million cubic metres in 1982; remained relatively constant between 1983 and 1986, and generally declined between 1987 and 1992.

Other discovered recoverable resources of 395 million cubic metres will likely be recovered by the future implementation of improved recovery techniques in the discovered pools of western Canada. We estimate that this future application of improved recovery techniques in selected light oil pools in western Canada will improve overall recovery efficiency in these pools by nearly five percentage points to an average of 33 percent.

Our estimate of **undiscovered recoverable resources** amounts to some 519 million cubic metres (Tables 7-1 and A7-2). This estimate is based on the GSC's estimate for recoverable light oil of 570 million cubic metres in the WCSB at year-end 1985.[4] We have updated this estimate to year-end 1992 by subtracting discoveries made since that time and by making adjustments for extensions to existing pools. The assumed recovery factor for future discoveries is 29 percent. This is consistent with the expected recovery of 33 percent in currently established pools by primary and improved recovery methods. We anticipate that future discoveries in western Canada will be smaller and possibly of poorer quality and may, therefore, have lower overall recovery. However, we also anticipate that implementation of recent technological advances will tend to have an offsetting effect.

We have disaggregated our total estimate of undiscovered resources for the WCSB to the provincial level by assuming that the undiscovered oil in place in each province is proportional to the discovered oil in place of that province (Table A7-2). We have provided this break-down because we consider it to be useful for comparative purposes. However, this disaggregation is not supported by a detailed geological analysis and should, therefore, be used with caution.

The estimated ultimate recoverable resources of light oil in the WCSB are compared with the corresponding estimates from our 1988 and 1991 reports in Table 7-2. The latest estimate is 183 million cubic metres higher than the 1991 estimate because of our recognition of further technological improvements in crude oil recovery.

7.2.2 Supply Costs

Supply costs for **other discovered recoverable resources** in the WCSB reflect the costs of oil to be recovered by future implementation of improved oil recovery (IOR) methods in established pools. These half-cycle costs are estimated for projects identified in a screening process as IOR prospects. Estimated supply costs for new waterflood projects exceed $10 per barrel. Supply costs for hydrocarbon miscible projects depend partly on the costs of injected materials, but generally range upwards from about $20 per barrel.

Supply costs for **undiscovered recoverable resources** represent the costs of finding, developing and producing new discoveries or extensions to existing pools. The main determinants of these costs are resources added per metre of exploratory drilling (Figure 7-5), and the costs of exploratory and development drilling per metre (Figure 7-6). We have relied on CAPP statistical data for the estimation of the input costs

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4   GSC Paper 87-26, Conventional Oil Resources of Western Canada (Light and Medium), 1988.

TABLE 7-2

Ultimate Recoverable Resources of Conventional Light Oil – WCSB

(millions of cubic metres)

	1994 Report	1991 Report	1988 Report
Initial Established Reserves	2 355	2 270	2 219
Other discovered resources	395	295	295
Undiscovered resources[1]	519	521	523
Total (ultimate)	**3 269**	**3 086**	**3 037**

1   Based on the 1988 Geological Survey of Canada's median estimate adjusted to year 1992.

Source: Appendix Table A7-2

associated with the exploration, development and production of new reserves. Since these data are not classified into light and heavy categories, our estimates are averages for all conventional crudes in the WCSB.

Variability of the historical additions rates and costs illustrates the uncertainty associated with predictions of future supply costs for reserves additions from undiscovered resources. This uncertainty relates to the assumptions regarding the impact of technological change on costs and projections of finding rates. Our estimated supply costs for reserves additions from undiscovered recoverable resources in the WCSB are shown in Figure 7-7.[5]

The average full-cycle supply cost for conventional light and heavy oil reserves additions is currently estimated at around $18 per barrel. The corresponding average half-cycle cost is around $13 per barrel, implying a finding cost of $5 per barrel. These costs are calculated as the ratios of the 1992 expenditures (as reported by CAPP) to the average primary reserves additions over the period of 1991 to 1993. The latest

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5   Detailed description of the methodology underlying the supply cost curve is provided in the paper "Trends in Crude Oil and Natural Gas Reserves Additions Rates and Marginal Supply Costs for Western Canada" by B. Bowers and R. Kutney published in the Canadian Journal of Petroleum Technology, Volume 28, 1989.

FIGURE 7-5

Trend of In-place Oil Resources Discovered Per Metre Drilled – WCSB
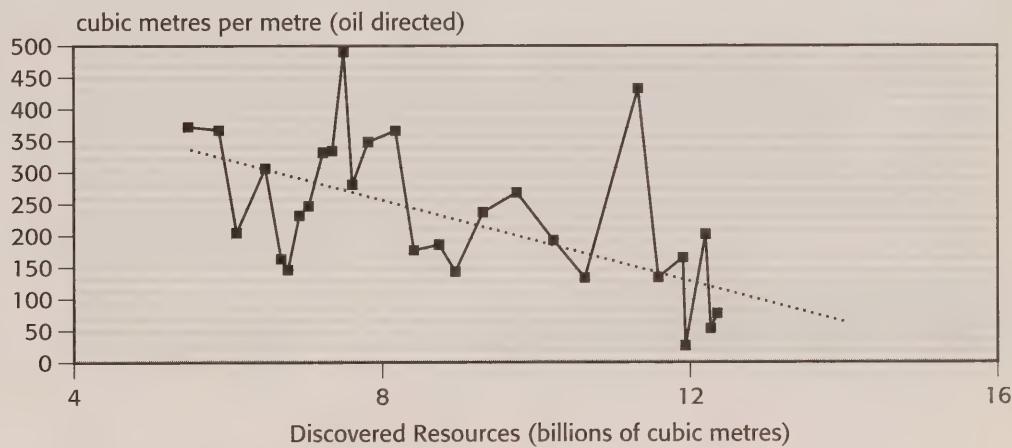
Source: Appendix Table A7-4

FIGURE 7-6

Historical Drilling Cost Per Metre – WCSB
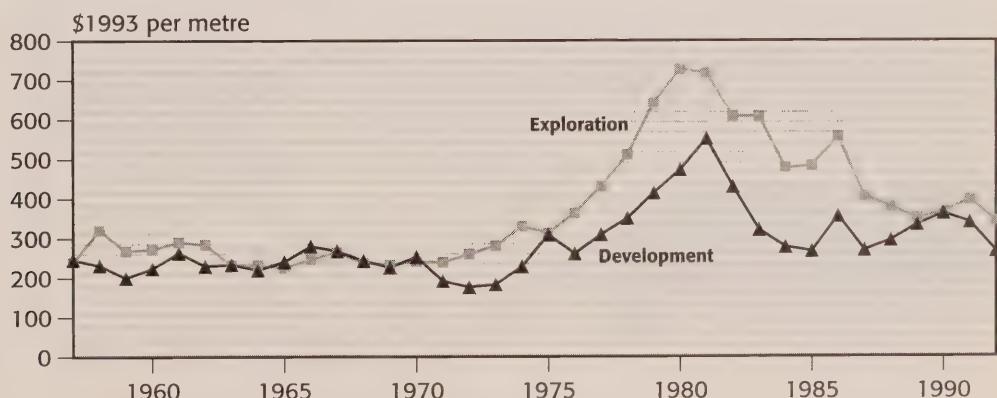
estimates are dramatically lower than our 1990 estimates of $25 and $18 for full and half-cycle costs respectively. Even though the estimates have been very erratic in the past, reflecting the random nature of discoveries and the impact of changing oil prices, this impressive cost reduction is undoubtedly related to industry restructuring and technological progress in recent years.

Among new technologies, horizontal drilling seems to have had a particularly strong effect. Our analysis of the impact of horizontal drilling in Western Canada[6] indicates that the technology tends to reduce unit supply costs compared to vertical drilling. For light and medium oil, the average cost reductions also show large variations across areas examined, ranging from zero in the Little Bow area to as much as $6 per barrel in the Midale area. The analysis of cost components suggests that these reductions result mainly from the production acceleration effect, increased production per well and royalty incentives for horizontal wells.

The horizontal drilling study lends support to the $13 estimate for half-cycle costs associated with reserves additions in the WCSB from infill wells. The costs estimated in the study for light and heavy oil pools average $11 for horizontal wells (with a $10-14 range) and $14 for vertical wells (with a $10-20 range). In 1992, horizontal oil development wells were drilled at a 1:5 ratio to vertical wells, which implies a weighted average supply cost of $13.50.

Based on the historical supply cost curves and resource limitations, both full and half cycle costs for undiscovered recoverable resources are projected to rise

gradually in the Current Tech case, as new prospects become less accessible and more expensive to produce. However, in the High Tech case, technological improvements are expected to partially offset the tendency for supply costs to increase over time. Consequently, the half-cycle costs are projected to fall slightly, while the full-cycle costs are projected to grow only modestly (Figure 7-7). The reserves additions from infill drilling in established pools have recently increased as a share of total reserves additions. This trend tends to increase the importance of half-cycle costs in the industry's economic analysis. These costs may now be more representative of the industry's actual performance than traditionally used full-cycle costs.

7.2.3   Reserves Additions

Reserves additions in the **other discovered recoverable resources** category include those arising from the future application of improved recovery methods (such as horizontal drilling, waterfloods and miscible floods) in established pools. We identify potential improved recovery projects through the use of such screening criteria as pool size, net pay, and porosity. Potential reserves additions are then calculated for the identified prospective projects by applying estimated incremental recovery factors to the original oil-in-place for these prospects. We then compare estimated supply

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6   NEB's working paper *Horizontal Oil Wells: Economics and Potential Impact on Reserves and Supply of Canadian Conventional Oil*, June 1993.

FIGURE 7-7

Full Cycle Costs for Reserves Additions from Exploratory Drilling – WCSB
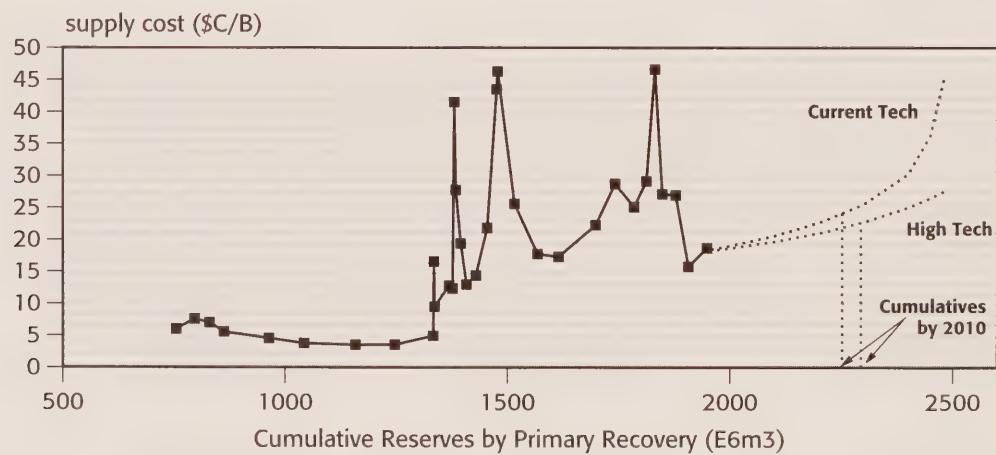
Source: Appendix Table A7-5

costs for these projects with anticipated crude oil prices to estimate the reserves additions in a given case.

Reserves additions resulting from infill drilling in conventional light oil pools are estimated to be 208 million cubic metres in both the Current Tech and High Tech cases. Estimated waterflood reserves additions over the projection period amount to about 80 million cubic metres in the Current Tech case and about 105 million cubic metres in the High Tech case. Reserves additions for new miscible flood projects are estimated to total 35 million cubic metres in the Current Tech case and 66 million cubic metres in the High Tech case. Reserves additions from development drilling in conventional light oil pools are estimated at 323 and 379 million cubic metres in the Current Tech and High Tech cases respectively (Table A7-7).

Reserves additions resulting from the future application of chemical flooding are not included in the

FIGURE 7-8
Oil-Directed Development Drilling – WCSB

Current Tech Case
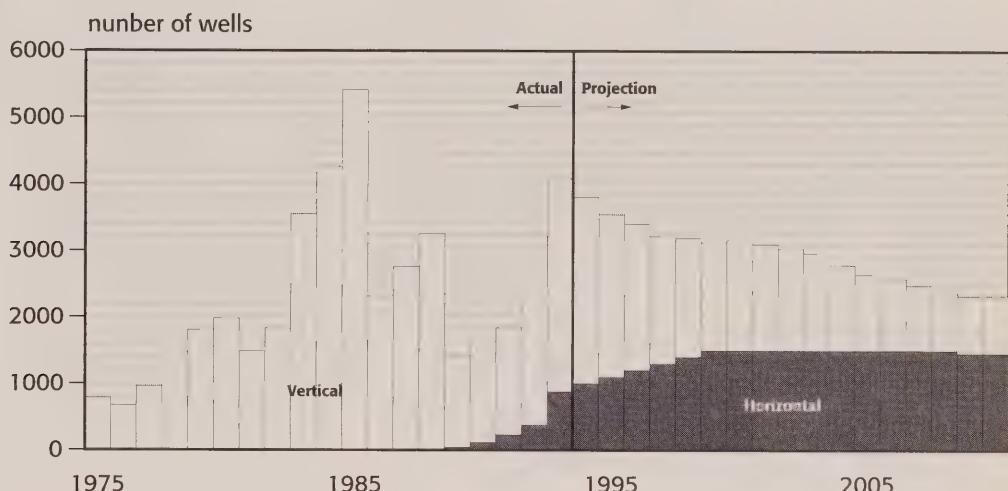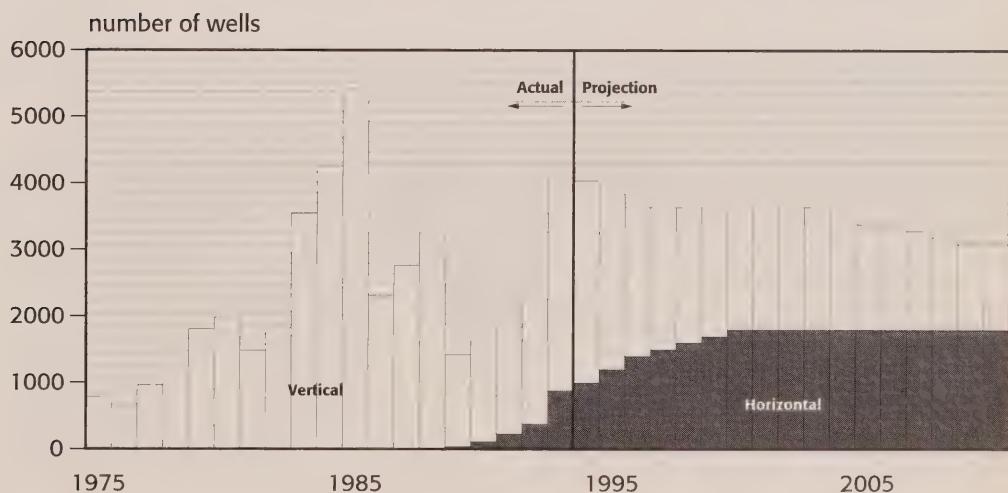
High Tech Case

Source: Appendix Tables A7-7 and A7-9

total. Even in the High Tech case these additions would likely not exceed 10 million cubic metres which is within the range of accuracy for projected reserves additions from other discovered recoverable resources.

With regard to **development drilling activity**, we determined the numbers of horizontal and vertical wells required to bring on the anticipated reserves additions using estimates of average reserves per well. Based on recent drilling data ("Horizontal Drilling Trend" inset), we projected the growth in horizontal well drilling to reach annual plateau levels of 1 500 wells by 1999 in the Current Tech case and 1 800 wells by the year 2000 in the High Tech case. With these assumptions, the estimated numbers of vertical wells required to develop projected reserves additions decline over the projection period as shown in Figure 7-8.

Our projections of reserves additions from **undiscovered recoverable resources** in the WCSB are derived using projected numbers of oil-directed exploratory wells (Figure 7-9) and projected resources added per unit of drilling (Figure 7-5) broken down into light and heavy oil categories.

In our Current Tech case, we assume that the incremental supply costs of conventional oil from the WCSB rise only modestly over the forecast period. This assumption combined with the flat projection for crude oil prices, imply that the motivation to explore for oil in the WCSB will be roughly constant over the forecast period and that oil-directed **exploratory drilling activity** levels will also remain relatively constant. For the Current Tech case our projected level of activity is 1 000 exploratory oil-directed wells per year, which is

FIGURE 7-9

Oil-Directed Exploratory Drilling – WCSB

Source: Appendix Table A7-7
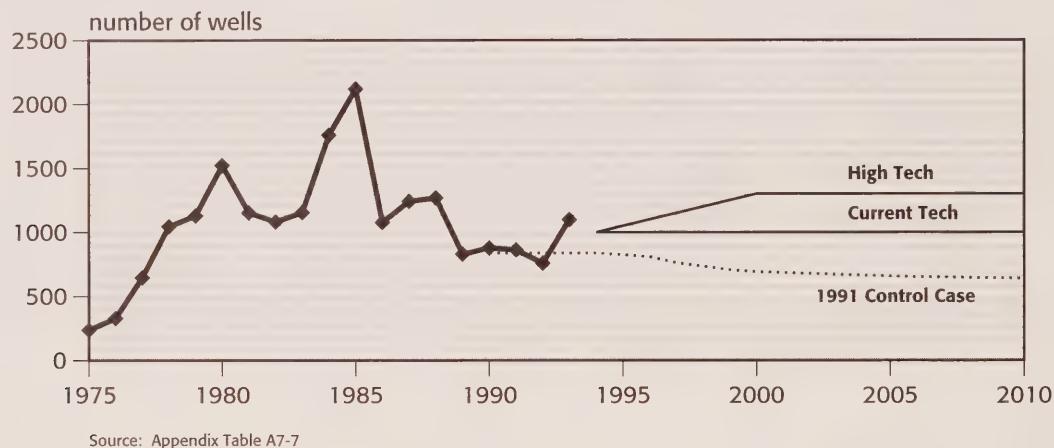
FIGURE 7-10

Light Oil Reserves Additions – WCSB

Source: Appendix Table A7-3 and A7-7

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
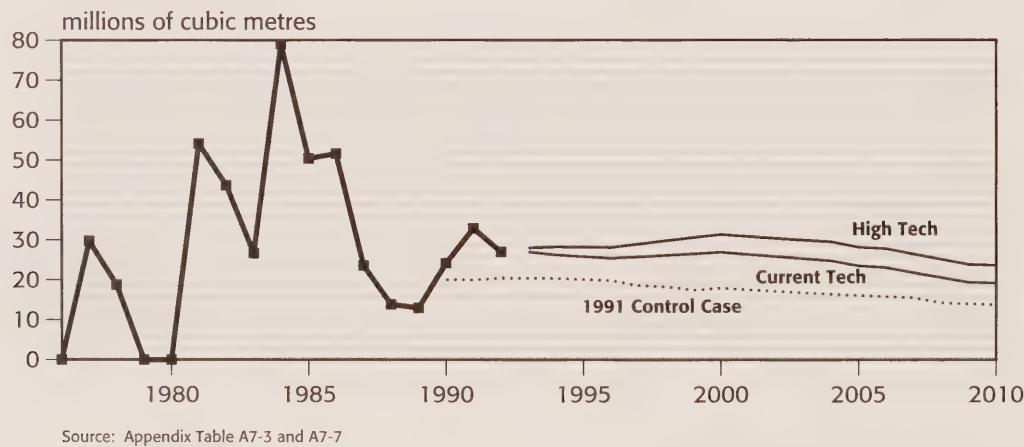
consistent with the recent historical levels. For the High Tech case, the number of exploratory wells is expected to grow to 1 300 by the year 2000, and stay at that level thereafter (Figure 7-9). Consistent with recent historical data, we have assumed that 55 percent of total exploratory wells in both technology cases will be in the light oil exploration category and 45 percent in the heavy oil category.

Reserves additions associated with primary recovery of conventional light crude oil in western Canada resulting from our projections of exploratory drilling activity are estimated to total 94 and 106 million cubic metres in the Current and High Tech cases respectively (Table A7-7). Annual levels of these additions tend to decline over the projection period as the resource becomes depleted and the prospects for new discoveries diminish.

Projected annual reserves additions of conventional light crude oil in western Canada are compared with those in the 1991 Report in Figure 7-10.

7.2.4   Projected Field Supply

Projected supply of conventional light crude oil comprises supply from both established reserves and reserves additions. This total supply is broken down by province in Table A7-11. For this disaggregation, we assumed that supply from each category of reserves additions is proportional to the current productive capacity of that category in each province. While this assumption may not be strictly accurate, we believe that it provides a reasonable basis for the projection of productive capacity from reserves additions by province.

Supply from currently **established reserves** of light crude oil in western Canada is projected to decline in both cases from 140 thousand cubic metres per day in 1992 to 13 thousand cubic metres per day in the year 2010 (Tables A7-6 and A7-7). This implies an average annual decline of 15 percent compared to 12 percent projected in the 1991 Report and 11 percent in the 1988 Report.

In Alberta, the older, larger pools that were once the mainstay of Alberta's supply are now in the latter stages of depletion. Poorer-than-expected production has resulted in cuts in remaining established reserves and projected supply for several of these pools, including Pembina Cardium, South Swan Hills BHL A&B and Bonnie Glen D-3A. However, the recent initiation or expansion of improved oil recovery projects in a number of pools, including Virginia Hills BHL, Acheson D-3A, Kaybob BHL A and several Pembina Keystone Belly River pools, may partially offset this general decline. A large portion of Alberta's production is derived from recently developed pools in the Provost, Rainbow and Peace River Arch areas.

In Saskatchewan, a major factor impacting light crude oil supply is the use of horizontal wells to enhance production and recovery, especially in southeast Saskatchewan. Supply of light oil from Saskatchewan's established reserves was 12 700 cubic metres per day in 1993, approximately 15 percent higher than in 1990.

In Manitoba, the supply from established reserves has been declining at a fairly constant rate of about 4 percent, reflecting the moderate level of development and exploration activity over the last several years.

FIGURE 7-11

Supply of Conventional Light Crude Oil – WCSB
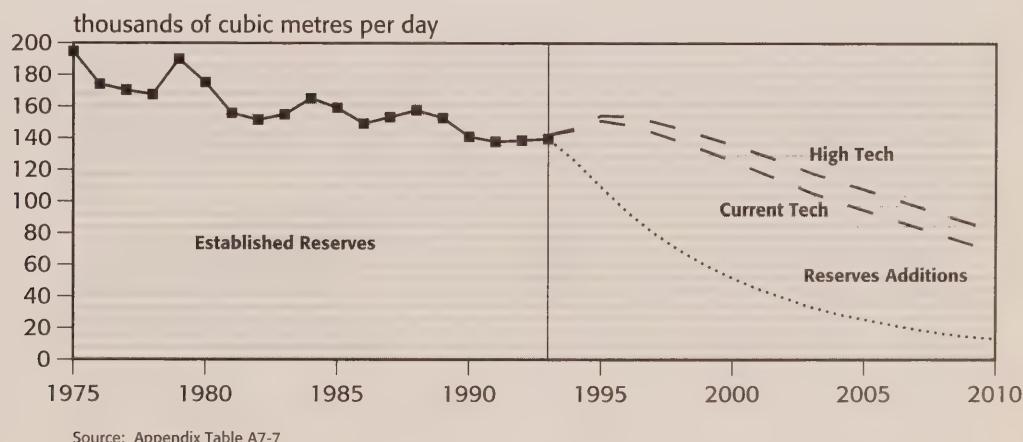
Source: Appendix Table A7-7

British Columbia's historical production decline has been moderated by better-than-expected performance and increases in reserves in several fields, including Eagle, Eagle West, Inga, and Boundary Lake.

Supply from **reserves additions** in western Canada is projected to increase to about 56 and 69 thousand cubic metres per day by the year 2010 in the Current Tech and High Tech cases respectively. Horizontal production wells contribute over three-quarters of these additions in both cases (Table A7-7). Supply from reserves additions is insufficient to offset the decline of the productive capacity from established pools in both cases.

In the Current Tech case, supply of conventional light crude oil (from established reserves and reserves additions) for the WCSB increases from the 1993 level of 142 thousand cubic metres per day to 151 thousand cubic metres per day in 1995, and then declines to 69 thousand cubic metres per day in 2010 (Figure 7-11). The projection for the High Tech case has a similar trend but at a somewhat higher level, rising to 154 thousand cubic metres per day in 1995 and then falling to 82 thousand cubic metres per day in 2010. These trends reflect the acceleration effect caused by our projection of horizontal wells (Figure 7-8) and their production profiles (higher initial rates and steeper declines) compared to vertical wells.

7.3   CONVENTIONAL HEAVY OIL – WCSB

This section discusses the recoverable resources, supply costs and reserves additions, and projected field supply for conventional heavy crude oil in the WCSB. The orientation of these aspects within the overall analytical framework is illustrated by the diagram in Figure 7-1 and the resource numbers stated below are summarized in Table 7-1.

7.3.1   Resources

For conventional heavy crude oil, 0.87 billion cubic metres or approximately three quarters of the estimated **recoverable resource potential** of 1.13 billion cubic metres, has been discovered. Of these discovered resources, about 0.41 billion cubic metres have been produced and 0.45 billion cubic metres remain to be produced. A significant portion of the remaining reserves is awaiting exploitation through improved recovery techniques. The extent of this exploitation depends on future oil price increases or reductions in supply costs.

Growth of **initial established reserves** averaged 16 million cubic metres per year between 1981 and 1988. Since year-end 1989, these reserves have increased by 77 million cubic metres (Figure 7-12). Approximately 75 percent of this increase was from discoveries, extensions to existing pools and infill wells. The remaining 25 percent was due primarily to improved pool performance in a number of pools as a result of upgraded fluid-handling capacity and the implementation of various production enhancement techniques.

In 1991 and 1992, most of the reserves additions stemmed from the application of horizontal drilling. This is particularly true for Saskatchewan. Several projects in west-central Saskatchewan, such as Senlac, Winter and Long Lake, were developed almost

FIGURE 7-12
Established Reserves of Conventional Heavy Oil – WCSB

Source: Appendix Table A7-3
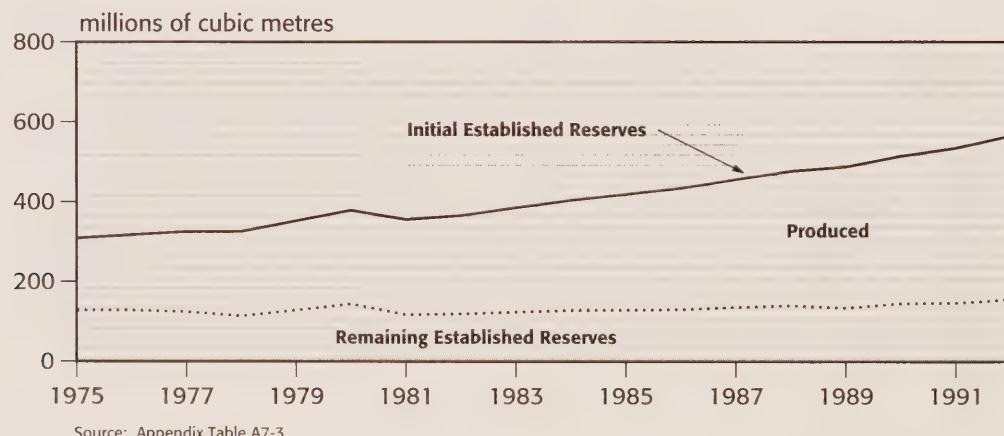
exclusively with horizontal wells, while in southeast Saskatchewan horizontal infill wells in existing pools led to substantial reserves additions. In Alberta, the Provost/Hayter and Hays/Ronalane/Taber areas experienced very active drilling programs over this period, contributing the majority of reserves additions.

On average only 8.4 percent of the heavy crude oil in place is recoverable by primary recovery techniques. Improved recovery brings the estimated overall recovery of established reserves to approximately 13.7 percent in 1992 (derived from Table A7-2). This recovery factor compares with a 12.7 percent factor registered in 1989.

Cumulative production amounts to 47 percent of the recoverable resource discovered to date.

The **remaining established reserves** are estimated to be 155 million cubic metres as of 31 December 1992, which is an increase of 21 million cubic metres from the 31 December 1989 estimate quoted in the previous report (Table A7-3 for historical data). During the 1960s and 1970s, remaining established reserves of conventional heavy crude oil remained relatively constant, as increases in initial established reserves generally corresponded to production (Figure 7-12). Between 1981 and 1989, remaining established reserves have increased by an average of 2.1 million cubic metres per year as reserves additions outpaced production in every year except 1989.

While the remaining reserves have increased by nearly 16 percent compared to those stated in the 1991 Report, the corresponding projections of first year supply indicate an increase of 34 percent. Over this time period, the Reserves Life Index (RLI) for the first year of the respective forecasts has dropped from 7.6 to 6.5. This acceleration of production is due mainly to the impact of horizontal drilling. Production from horizontal wells as of year-end 1993 accounted for 16 percent of total heavy crude oil production in the WCSB.

Other discovered recoverable resources totalled 300 million cubic metres at the end of 1992. We estimate that future implementation of improved recovery techniques in established pools will increase recovery by approximately seven percent, to an overall average of 21 percent (derived from Table A7-2). Most of this incremental recovery could be achieved through the application of horizontal drilling, thermal improved recovery techniques, or a combination of both.

Our estimate of **undiscovered recoverable resources** amounts to 260 million cubic metres as of year-end 1992. This represents a decrease of some 10 million cubic metres from the year-end 1989 estimate provided in the 1991 Report. The assumed recovery factor for these resources is 15 percent compared to an expected recovery of 21 percent for the current discovered resources.

The estimated ultimate recoverable resources of heavy oil in the WCSB are compared with the corresponding estimates from our 1988 and 1991 reports in Table 7-3. The latest estimate is some 47 million cubic metres higher than the 1991 estimate because of our recognition of technological improvements in crude oil recovery techniques.

7.3.2 Supply Costs

Supply costs for **other discovered recoverable resources** in the WCSB reflect the costs associated with future implementation of IOR in established pools. In particular, supply costs for steam injection projects range upwards from about $10 per barrel, but depend in part on prices of fuels used to generate steam. The steep increases in gas prices projected in the Current Tech case would approximately double the costs of steam for these projects from the present range of $2-3 per barrel of heavy oil produced.

TABLE 7-3

Ultimate Recoverable Resources of Conventional Heavy Oil – WCSB

(Millions of Cubic Metres)

	1994 Report	1991 Report	1988 Report
Initial Established Reserves	565	488	434
Other discovered resources	300	320	370
Undiscovered resources	260	270	250
Total (ultimate)	**1 125**	**1 078**	**1 054**

Source: Appendix Table A7-2

Supply costs for **undiscovered recoverable resources** of conventional heavy oil were discussed together with the costs for conventional light oil in section 7.2.2.

As for the **established reserves**, supply cost estimates are based mainly on our horizontal drilling study. The study indicated that this technology tends to reduce unit supply costs compared to vertical well drilling. This is particularly critical for heavy oil projects which typically have to contend with much lower netbacks. For heavy oil wells in the Lloydminster area, the study estimated that the average half-cycle cost is $10 for horizontal infill wells compared to $20 for adjacent vertical wells. In the heavy oil area of Provost/Hayter, the average cost reduction is more modest – from $12 for vertical wells to $10 for horizontal wells.

7.3.3 Light/Heavy Oil Price Differentials

Physical characteristics of heavy crudes are different from those of light crudes, making heavy crudes generally less desirable from a refiner's point of view. This is reflected in the price differentials between light and heavy crudes. These differentials are projected for alternative cases based on corresponding coking differentials, heavy oil supply/demand balances and the price levels for light oil.

In a balanced market, prices for Canadian light and heavy crude oils are determined by Chicago prices for WTI and Maya crudes, respectively. Since the Bow River blend is very similar in quality to Maya, and represents over one-third of total Canadian heavy oil production, its posted prices at Hardisty are used in our report as the benchmark for all Canadian heavy crudes. The various factors that affect this price differential are discussed in the following paragraphs.

Heavy crudes have lower prices than light crudes due to higher yields of lower-value products. For instance, the Lloydminster heavy oil blend generates 70 percent of heavy ends compared to only 36 percent for WTI crude. The heavy components can be used either to produce heavy oil products, or run through catalytic and thermal conversion units to obtain lighter products. Lighter products fetch higher prices, but are also more expensive to produce from heavy crudes than from light crudes. The refiners' choice of the feedstock mix is, therefore, determined by the relative market values of products (net of operating costs) obtained from heavy oil versus light oil feedstocks processed at coking refineries. These differences, also called "coking differentials", determine the minimum light/heavy price differential required by the refiners. That minimum or "base"

differential has been around $3 per barrel, the sum of approximately equal differences in market values of products and in operating costs.

When the existing heavy oil conversion capacity is fully utilized, processing of incremental heavy crudes requires the installation of additional conversion units. The refiners will consider such an investment if they can expect to recover the fixed costs of new units. This investment threshold is therefore determined by the same factors as the base differential (i.e., market values of products and operating costs), with the addition of fixed costs. The magnitude of the threshold ranges from $7 per barrel for U.S. refineries to $9 for Canadian refineries and $12 for new stand-alone upgraders in Alberta.

Fluctuations of the differentials within this sustainable range of $3 to $9 reflect changes in global and local supply/demand balances for heavy crudes. The demand is driven by: economic growth, weather patterns, available conversion capacity, competition from alternative energy sources and environmental regulations. The supply is driven by: available reserves, heavy oil prices, and the impact of technology on extraction and upgrading costs.

Projected Canadian light/heavy oil price differentials are illustrated in Figure 7-13. Over the short term, Canadian differentials are expected to narrow further in both technology cases from the 1993 level of $5.75 to $5.00 in 1994, due to the impact of such factors as: persistent low oil prices and a lighter world crude slate. Differentials are then projected to widen gradually to $6.50 by the year 2000 in the Current Tech case, as a result of falling demand for residual fuel oil and growing supply of Canadian heavy oil. After 2000, differentials are projected to stay flat at $6.50, as Canadian heavy oil supply begins to decline. In the High Tech case, technology-driven cost reductions are expected to result in even faster increases in heavy oil supply. This, combined with the need to access lower-netback markets, results in a sharp increase in the differential around the year 2000, followed by more gradual increases to around $9.50 by 2010.

Two additional projections were developed for light/heavy price differentials in the Low and High Price sensitivities. In the US$15 price scenario, the differentials are projected to remain constant at only $4.50, reflecting reduced availability of Canadian heavy crudes and narrower product price differentials. In the US$30 price scenario, the differentials are expected to widen dramatically for exactly the opposite reasons, reaching $10 in year 2000 and $11 by 2010.

7.3.4 Reserves Additions

Reserves additions resulting from infill drilling in currently established pools are in both technology cases estimated to be 88 million cubic metres based on available drilling locations. Estimated waterflood reserves additions over the projection period amount to 85 million cubic metres in the Current Tech case and 108 million cubic metres in the High Tech case. Additions for the steam injection projects are estimated to total 90 million cubic metres in the Current Tech case and 120 million cubic metres in the High Tech case. Our estimates of reserves additions over the projection period from development drilling in conventional heavy oil pools total 263 and 316 million cubic metres in the Current Tech and High Tech cases respectively (Table A7-9).

Reserves additions resulting from the future application of the in situ combustion process, although not included in the total, could result in additional reserves being developed in the High Tech case. We do not believe that these volumes would be significant during the projection period.

Our projections of exploratory drilling activity in western Canada (section 7.2.3) result in reserves additions of 80 and 91 million cubic metres from primary recovery in the Current and High Tech cases respectively (Table A7-9). Annual levels of these additions tend to decline over the projection period, as the ultimate resource potential is approached and prospects for new discoveries diminish.

Projected annual reserves additions from **other discovered** and **undiscovered recoverable resources** of

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FIGURE 7-13

Projected Light/Heavy Oil Price Differentials
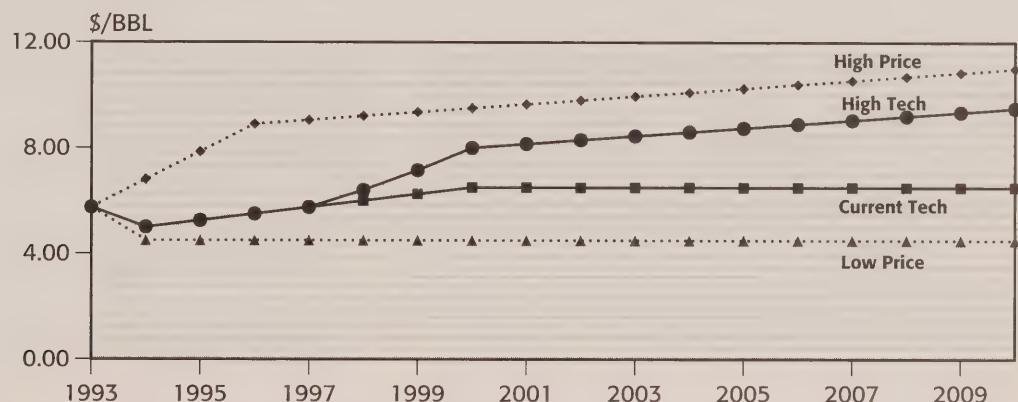
FIGURE 7-14

Heavy Oil Reserves Additions – WCSB

Source: Appendix Tables A7-3 and A7-9
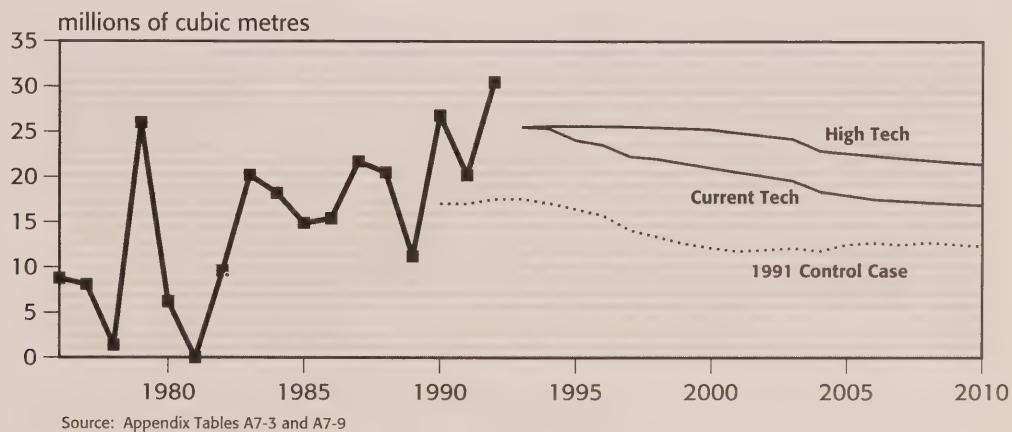
conventional heavy oil are calculated in the same way as those for light oil. These additions are compared with those in the 1991 Report in Figure 7-14.

7.3.5 Projected Field Supply

Projected supply of conventional heavy crude oil comprises supply from established reserves and from reserves additions. Both components are very sensitive to light/heavy oil price differentials (discussed in section 7.3.3) which ultimately determine the producer netbacks for conventional heavy crude oils. Total supply is broken down by province in Table A7-11. For this disaggregation, we have made the same assumptions as for light crude oil.

Supply from currently **established reserves** is projected in both cases to decrease (from 65 thousand cubic metres per day in 1993) to 3 thousand cubic metres per day in the year 2010 (Tables A7-8 and A7-9).

In Alberta, the Provost/Hayter and Hays/Ronalane/ Taber areas have experienced very active drilling programs in recent years, contributing the majority of production increases for Alberta. Production from horizontal wells is playing an increasingly important role in Alberta's heavy crude supply picture. At year-end 1993 there were 178 horizontal wells in Alberta's heavy oil fields, producing 3.3 thousand cubic metres per day, or approximately nine percent of the provinces conventional heavy crude oil supply.

Horizontal drilling also contributed substantially to supply increases in southeast Saskatchewan. In November 1993, there were 437 horizontal wells, producing some 7.3 thousand cubic metres per day, or approximately 26 percent of Saskatchewan's heavy crude oil. To a lesser extent, increased supply can be attributed to improved pool performance in a number of pools as a result of the implementation of various production enhancement techniques, including the initiation or expansion of IOR projects. One notable example is the recent implementation of carbon dioxide miscible flooding in the Midale pool.

Supply from **reserves additions** is projected to increase by the end of the projection period to about 47 and 60 thousand cubic metres per day in the Current and High Tech cases respectively. Future horizontal wells contribute nearly half of these additions in both cases (Table A7-9). Supply from reserves additions is almost sufficient to offset the decline of the productive capacity from established pools in the High Tech case, but not in the Current Tech case.

In the Current Tech case, supply of conventional heavy crude oil (from established reserves and reserves additions) for the WCSB increases from the 1993 level of 65 thousand cubic metres per day to 90 thousand cubic metres per day in 1997, before declining to 50 thousand cubic metres per day in 2010 (Figure 7-15). The projection for the High Tech case has a similar profile, but at a higher level. As in the projections for light oil, this profile is again a reflection of the expected growth of horizontal drilling (Figure 7-8).

7.4 FRONTIER LIGHT OIL

This section discusses the recoverable resources, supply costs and reserves additions, and projected supply of light crude oil from the frontier areas. The orientation

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FIGURE 7-15
Supply of Conventional Heavy Crude Oil – WCSB
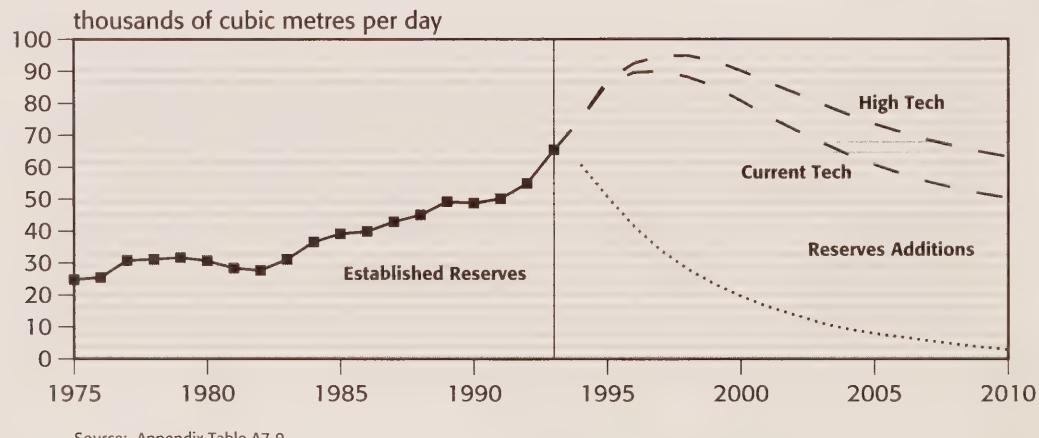
Source: Appendix Table A7-9

of these aspects within the overall analytical framework is illustrated by the diagram in Figure 7-1 and the resource numbers stated below can be found in Table 7-1.

7.4.1 Resources

Discovered recoverable resources of 580 million cubic metres represent 21 percent of the ultimate potential of frontier basins with discoveries (estimated at 2.8 billion cubic metres) and 14 percent of the ultimate recoverable resource of all frontier areas (estimated at 4.2 billion cubic metres). As a result of low exploration levels, discovered recoverable resources have remained at much the same level as in 1991. The significant increase in the ultimate recoverable potential reflects the recognition of additional speculative potential in basins which lack confirming discoveries. These include offshore British Columbia, and Georges Bank and the Laurentian sub-basin off the east coast. However, none of the resources in this category impact our supply projections in this study.

The **remaining established reserves** of 123 million cubic metres which the Board recognized in the frontier regions represent 23 percent of all conventional light oil resources. Established reserves in the frontier are limited to four projects which are either producing or have development plans in place. These projects are: Norman Wells and Bent Horn, Cohasset/Panuke, and Hibernia. In the Norman Wells field located in the Mackenzie Valley, over half of the initial established reserves have now been produced. The remaining established reserves of 18 million cubic metres may be increased by a planned improved recovery scheme and development of marginal areas of the field. About one million cubic metres remain in the Bent Horn field in the Arctic Islands, but this estimate is subject to significant geological uncertainty. In the twin-field Cohasset/Panuke project offshore Nova Scotia, about one third of the estimated established reserves of 5 million cubic metres was produced by year-end 1993. Established reserves in the Hibernia field offshore Newfoundland have been increased to 98 million cubic metres, reflecting new estimates by the Hibernia partners. There is a possibility for further growth of reserves at Hibernia, particularly as the Avalon and other subsidiary reservoir units are more thoroughly evaluated during field development.

Our 438 million cubic metres estimate for **other discovered resources** is based on various sources. For the east coast, we have used estimates by the Canada-Newfoundland Offshore Petroleum Board (CNOPB) and the Canada-Nova Scotia Offshore Petroleum Board

(CNSOPB) for regions under their respective jurisdictions, and adjusted these estimates for volumes recognized as established reserves. For other frontier regions, we have used our own estimates for the Mackenzie Valley and Yukon. Elsewhere, we have used estimates based largely on previous work by the former Canada Oil and Gas Lands Administration. We recognize that methods of estimation used to determine discovered resources differ among estimators, and that the various estimates may not be strictly comparable. In the previous report, natural gas liquids and condensate associated with the frontier discoveries were included in some of our oil resource estimates. These volumes have now been removed where the resources are unlikely to contribute to light oil supply (e.g., in non-associated gas pools). The resource estimates for the Nova Scotia offshore and the Mackenzie Delta have been adjusted accordingly.

As for the **ultimate recoverable resource potential**, we have relied on the GSC estimates. These estimates of basin potential are usually expressed as ranges with associated probabilities of occurrence. For the purpose of aggregating resource estimates, the average expectation (mean) was selected from the probability distribution for each assessment area. The **undiscovered recoverable resources** of 3.6 billion cubic metres was estimated by subtracting the currently discovered recoverable resources from the total potential. Of this total, 2.3 billion cubic metres are in basins with existing oil discoveries. The remaining 1.3 billion cubic metres fall in the category "Other Frontier Basins" which lack confirming discoveries.

7.4.2 Supply Costs

Cost estimates were developed for major frontier projects currently under consideration, based on approved development plans and data obtained from the Nova Scotia and Newfoundland and Labrador governments and federal/provincial offshore petroleum boards. These estimates were then used to establish a likely range of supply costs for other unspecified projects which may contribute to frontier supply during the projection period.[7]

Supply costs for the proposed expansion of the **Norman Wells** project are estimated at about $13-15 per barrel. Even with further development drilling, production is expected to decline gradually, thereby augmenting spare capacity on the Norman Wells

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7   Additional information on the development schemes and costs for frontier projects can be found in a 1992 study by Croasdale and McDougall entitled *A Research Planning Study for Canada's Frontier Oil and Gas.*

pipeline. This will tend to encourage exploration for new reserves along the pipeline corridor.

The **Cohasset/Panuke** project located 150 kilometres offshore Nova Scotia has been on seasonal production since 1992. However, two of the four wells drilled at Panuke are no longer producing due to water encroachment and other technical problems. As a result, the project's supply cost increased from the initial estimate of $20 per barrel.

Hibernia is the only new frontier project currently under construction. Production is planned to begin in late 1997 or early 1998. In the fall of 1993, the Hibernia consortium announced a new development plan which revised the project's reserves from 83.4 to 97.7 million cubic metres, and substituted 38 planned subsea completions with wells drilled from the Gravity-Based Structure (GBS). This modification was expected to reduce projected capital and operating costs by 20 percent without affecting originally anticipated production rates. However, subsequent cost overruns may offset these earlier savings implying that our 1991 supply cost estimate of about $32 per barrel[8] may still be fairly accurate.

The Hibernia project has the potential to improve its economic viability. This potential hinges mainly on possible increases in recovery efficiency, reserves additions, as well as on the development of NGL reserves. In order to increase oil recovery from the Hibernia sandstone, the operators may use waterflooding or selective miscible flooding. In addition, the recovery factor for the Avalon sandstone may improve beyond the present estimate of 15 percent. Although there is no approved development plan for the Avalon reservoir, the most likely option entails drilling some 25 deviated wells from the GBS.

Other discoveries in the same sedimentary basin as Hibernia are also candidates for development. Foremost of these is the Terra Nova oil field located 40 km southeast of Hibernia. No development plan has been submitted to the Canada-Newfoundland Offshore Petroleum Board (CNOPB) for the **Terra Nova** project as of time of writing. However, a senior representative of Petro-Canada, the largest interest holder, has recently indicated that the company has a strong preference for a floating production system to develop the field. Estimated capital costs for development using a semi-submersible production platform range between $2.2 and $3.7 billion. The lower estimate is somewhat speculative as it assumes the use of an existing rather than custom-built platform. These estimates are based on industry and government figures, and on published

estimates of drilling and transportation costs for Hibernia. With an additional $2.0 billion for operating costs, the implied unit supply costs range between $17 and $23 per barrel. These estimates are preliminary and may change if a different development scheme is adopted or if the resource estimate of 64.4 million cubic metres is revised. We have adopted the $23 figure for our Current Tech case as it is more conservative and consistent with other available estimates.

Among other discoveries in the basin, **Hebron and Whiterose**, with resources estimated at 31 and 28 million cubic metres respectively, may be centres of future activity. Smaller accumulations nearby, typically containing less than four million cubic metres, may be developed in conjunction with already developed fields using subsea connections. The NEB has not performed detailed cost analysis for any of these projects due to the lack of development plans and the great uncertainty associated with the resource estimates. Instead, we have used a 1990 study by the Newfoundland Department of Mines and Energy[9] which estimated that the minimum economically viable reserves size for the Grand Banks is 24 to 32 million cubic metres at an oil price of US$20 per barrel in 1990$ (or over $27 in 1993$). This threshold implies that supply costs for fields smaller than 32 million cubic metres would be in excess of $27, a figure confirmed by our in-house evaluation of a hypothetical project of that size.

This cost threshold may not be applicable to all fields offshore Newfoundland given wide variations in their characteristics. Growth of onshore infrastructure and future offshore production experience associated with Hibernia and Terra Nova could enhance the development prospects for some fields. Costs for individual projects will partly depend on the distance from the hub production facility. Required reductions in costs to below the economic threshold may be achieved through further improvements in subsea development technologies.

Turning to the northern frontiers, one major **Mackenzie Delta** operator indicated that half-cycle costs including transportation range between $24 and $36, depending on size of reserves and the pipeline. To account for reserves uncertainty, the company examined

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8   Cost estimates quoted in various trade publications vary considerably due to different underlying assumptions and methodologies. The lower estimates, some as low as $16 per barrel, do not conform with our definition of supply costs as they often exclude taxes and royalties and/or do not properly discount the future revenue streams.

9   *The Effects of Oil Price, Inflation, Interest Rates, and Current Exchange Rates on Offshore Project Viability.*

scenarios for reserves ranging from 8 to 64 million cubic metres. The respective transportation costs for these options are very sensitive to throughput, and range from $6-9 for a high-throughput, 20" pipeline bypassing the Norman Wells system, to $12-16 for a low-throughput, 12", extension of the Norman Wells system. The latter pipeline option is premised on an expected production decline from the Norman Wells field. The transportation costs and field supply costs for undiscovered fields in the Mackenzie Valley that are close to that pipeline may tend to be somewhat lower.

The **Amauligak** field is the largest discovered oil field in this region with recoverable reserves estimated at 55 million cubic metres. The NEB's 1991 analysis indicated that the supply cost for Amauligak, including pipeline transportation to Edmonton but excluding exploration and pre-development expenditures, would be around $29 per barrel. Our estimates were similar for smaller fields in the Mackenzie Delta-Beaufort Sea that may be developed in conjunction with Amauligak. Since 1991, there have been no new developments that would justify any significant revisions to these estimates. It should be noted that transportation by tanker could, potentially, be a viable alternative to the pipeline option.

Table 7-4 compares supply costs for major frontier projects at the wellhead or plant gate with projected wellhead prices for these projects. For the east coast offshore projects, supply costs in the Current Tech case generally range between $23-30 compared with the projected price range of $23-29. In the High Tech case, these supply costs are expected to fall by approximately 15 percent over the projection period to an $20-26 range. For the Mackenzie Delta/Beaufort Sea projects, supply costs (net of transportation costs) are between $13-16 in the Current Tech case, and between $11-13 in the High Tech case. Both cost ranges substantially exceed the projected wellhead prices of $5-11.

In conclusion, the above analysis indicates that, with the exceptions of the southern Northwest Territories and the Mackenzie Valley, frontier basins generally remain among the highest-cost sources of oil supply in Canada. With supply costs for new projects other than Terra Nova generally in excess of $27 in the Current Tech case, frontier offshore projects are marginally economic at projected mid-range prices, and very vulnerable to lower oil prices because of high capital costs and long lead times. The outlook for these projects will, in large measure, depend on the success of future

TABLE 7-4

Supply Costs and Projected Prices for Crude Oil Projects Considered in Projection
($1993 per barrel)

	Half-Cycle Costs at Field for Discovered Oil Resources		Projected Oil Prices at Field
	Current Tech	High Tech	1993-2010
Conventional Crude Oil			
Frontiers			
East Coast Offshore	23-30	20-26	23-29
MacKenzie/Beaufort	13-16	11-13	5-11[1]
Unconventional Crude Oil			
Bitumen			
Primary Recovery	9-12	8-10	12-16[2]
Steam-Assisted	11-15	9-13	12-16[2]
Synthetic Oil			
Stand-Alone Upgraders	25-30	22-26	21-27
Integrated Mining Plants	25-30	23-27	21-27

Notes:
1   Calculated as the price at Edmonton less a $16 transportation cost from the field. This cost could be substantially less for a high-throughput pipeline.
2   In the High Tech case the range is $11-14 due to the wider light/heavy price differentials.

efforts to reduce costs through improved frontier technology. Particularly critical will be the efforts to reduce the prohibitively high transportation costs which, in some frontier areas, remain the main factor hindering development.

7.4.3   Reserves Additions

Reserves additions in the **Norman Wells** field will occur through a horizontal drilling program proposed by Imperial Oil Ltd. which will access reserves located at the edges of the pool, which could possibly be miscibly flooded at later stages. With renewed exploration likely in the vicinity of Norman Wells, new pools with low connection costs may be discovered.

Exploration in the **Mackenzie Delta/Beaufort Sea** region, although currently at a low ebb, is aimed at discovering offshore fields comparable in size to Amauligak and onshore fields in the range of 16-32 million cubic metres. The discovery of such fields could be sufficient to warrant development and construction of a Mackenzie Valley pipeline if these fields were concentrated in one area. Under this circumstance, the development of existing discovered resources onshore in the Mackenzie Delta may be envisaged. Given the current inventory of discovered oil resources, the low level of exploration and high development and transportation costs in the Mackenzie Delta, development is unlikely within the projection period.

Reserves additions in the **Newfoundland offshore** are likely following the commissioning of the Hibernia field in 1997. The Terra Nova field, containing discovered resources of 64 million cubic metres could be developed using a floating production system. Development of this field would benefit from expanded local services which have supported the Hibernia project. Terra Nova could come on stream around the turn of the century with planning and regulatory approvals taking perhaps three years and development another two to three years. The rapidly evolving technology of offshore production is expected to facilitate development of smaller fields within the basin, making smaller scale or satellite development of such fields as Hebron, Whiterose and Ben Nevis possible after 2005. There is also good potential for further discoveries close to existing fields. For the Current Tech and High Tech cases, reserves additions of 64 and 95 million cubic metres were added, respectively, during the forecast period.

After the depletion of the Cohasset/Panuke fields by late 1996, there is no significant inventory of oil discoveries awaiting development **offshore Nova Scotia**. Future development in this region is contingent on additional discoveries which are not factored into our projections.

7.4.4   Projected Field Supply

Supply from **established reserves** in the east coast offshore regions is expected to make a considerable contribution to Canadian oil supply over the projection period. Production from the Cohasset/Panuke project is expected to average 5 100 cubic metres per day in 1994, then decline and cease in 1996. This project will be followed by Hibernia which is expected to start in 1997 and reach a peak of 19.8 thousand cubic metres per day by 1999.

In other frontier regions, we expect Norman Wells to enter a gradual decline which will bring production in 2010 to about 20 percent of the current level. Planned reserves additions within the field will slow the decline rate slightly. We also assume that Bent Horn in the Arctic Islands will continue producing oil at current low rates until 2008 for summer tanker shipment out of the Arctic.

The productive capacity projections for the frontier regions are summarized in Tables A7-6 and A7-10.

The supply from **other discovered resources** in the Current and High Tech cases is expected to come from offshore Newfoundland. This is a departure from the 1991 forecast which also included some production from the Beaufort Sea/Mackenzie Delta region. Our estimates of production and transportation costs for this northern region are unchanged from the last report, but now seem prohibitively high when compared to the substantially lower oil price projections. Oil development in the northern region may be linked to gas development which has been postponed in our new gas projections due to lower supply costs for gas in the WCSB. This view could be revised if crude oil discoveries in excess of 16 million cubic metres were made onshore Mackenzie Delta, or if a single offshore discovery in excess of 80 million cubic metres was made in the proximity of Amauligak.

The Terra Nova project is expected in the Current Tech case to start production in the year 2002, and add another 15.8 thousand cubic metres per day to supply by 2004. In the High Tech case, the project's start-up is brought forward to the year 2000. Terra Nova will be followed by the development of unspecified pools, so that total supply from the East Coast will plateau at about 35 thousand cubic metres per day after the year 2005.

By the year 2010, total oil produced from frontier areas is projected to reach 141.9 million cubic metres in the Current Tech case, and as much as 196.2 million

cubic metres in the High Tech case (Figure 7-16). These volumes are associated mainly with Hibernia and Terra Nova which jointly account for 91 percent and 76 percent of total frontier production in the two cases, respectively. The contribution of smaller satellite fields in the same area also becomes significant in the High Tech case, reaching over 21 percent of the total.

7.5   BITUMEN FROM ALBERTA OILSANDS

This section discusses the recoverable resources, supply costs and reserves additions for bitumen from Alberta oilsands, as well as projected field supply broken down into two categories: in situ bitumen and synthetic oil from integrated mining plants. The orientation of these aspects within the overall analytical framework is illustrated by the diagram in Figure 7-1 and the resource numbers stated below are summarized in Table 7-1.

7.5.1   Resources

For bitumen resources, we have adopted ERCB estimates for **discovered recoverable resources**. The total estimate of 49 billion cubic metres comprises about one billion cubic metres associated with the existing projects and 48 billion cubic metres associated with possible future development. Of the latter figure, approximately 9 billion cubic metres is attributable to surface mining and 39 billion to in situ processes.

Cumulative production amounts to 269 million cubic metres, which is only 0.5 percent of the discovered recoverable bitumen resources.

The **remaining established reserves** of 482 million cubic metres is the ERCB estimate. This figure includes 434 million cubic metres associated with surface mining at the sites of the two existing plants, and 48 million cubic metres associated with in situ techniques at currently active commercial and experimental oil projects.

7.5.2   Supply Costs

Supply costs for bitumen vary from project to project, depending on depth below surface, bitumen saturation, reservoir characteristics, viscosity of the bitumen and method of extraction. Deeper oilsands deposits may be exploited in situ by primary recovery if viscosities are relatively low, and/or by steam injection, whereas shallower deposits are typically accessed using mining methods. The recent increase in the number of *in situ primary recovery* projects is one of the most significant developments since the publication of our 1991 report. Based on our consultations, supply costs for such projects are estimated at $9 to $12, including average royalties and corporate taxes of about $2 (Table 7-4). The lower cost is associated with the most advanced horizontal drilling methods used in such prolific areas as Brintnell and Pelican Lake, whereas the higher cost represents traditional vertical wells in most regions.

Supply costs for *in situ steam-assisted* projects, which typically use natural gas for steam generation, are slightly higher than those for primary recovery projects, ranging between $10 and $16 per barrel. The $10 cost represents new, SAGD-type processes that are being tested by AOSTRA, Amoco, and Shell. The figure is based on AOSTRA's estimate for a 5 thousand cubic metres per day project entailing 30 well pairs drilled

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FIGURE 7-16
Supply from Frontier Regions

thousands of cubic metres per day

Source: Appendix Table A7-10
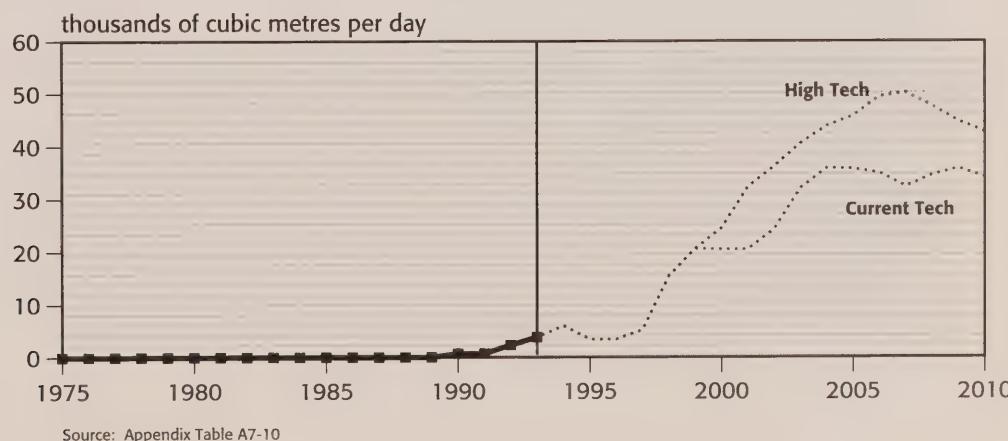
over 25 years at a capital cost of $450 million. More traditional "huff-and-puff" processes used by existing commercial projects, such as Cold Lake and Wolf Lake, generally fall in the higher end of the cost range. The above estimates imply that the costs of bitumen feedstock in the Current Technology case fluctuate between $11 and $14. Our extensive consultation with the operators indicated that further technological advances could lower these costs by 15 to 20 percent. The resulting $9-11 range has been used to develop bitumen supply projections in the High Tech case.

The above cost estimates are based on the 1993 average gas price of $1.50 per Mcf which translates into a steam cost of $3.50 per barrel of produced bitumen. In the Current Tech case, gas prices are projected to rise dramatically, exceeding $3 per Mcf by year 2005. This price level would likely encourage switching to coal for steam generation. It would also double the cost of steam to $7.00 per barrel of produced bitumen, pushing the $11-14 cost range up to $15-18. In the High Tech case, the impact on supply costs would be more modest due to smaller projected increases in gas prices.

Supply costs for synthetic oil from integrated mining plants are estimated in the Current Tech case at $25 to $30 (Table 7-4). The cost of Syncrude's expansion establishes the lower end of that range, whereas the cost of a grass-roots, OSLO-type, project

represents the upper end. In the High Tech case, the costs are assumed to fall by $2-3 to a $22-27 range. This assumption seems fairly conservative in light of a $15 per barrel (50 percent) reduction in operating costs achieved by Suncor and Syncrude over the past decade.

Based on Suncor's latest strategic plan, a further cost reduction of at least $5 per barrel from the present level is expected by the late 1990s. The reduction will be achieved through: (a) replacement of bucketwheel excavators by electric shovels and trucks; (b) improvements to the utilities plant (involving utilization of fluidized bed combustion); (c) modifications to the upgrader (involving removal of lighter fractions at the beginning of the process); and (d) improvements in operating practices. Suncor's longer-term plan entails developing one of two recently purchased leases by 1999 using standard mining and transportation practices. New technologies, such as SRT and hydrotransport, are also being evaluated for possible implementation.

Similar measures are being taken by Syncrude in an effort to reduce operating costs from $19 recently to $12-14 within the next few years. Turning to the company's expansion plans, operation on the north mine is considered along with other options, raising total capacity to 48 thousand cubic metres per day by 1998. A new mine will likely use electric shovels and trucks. This $1-billion expansion is contingent on the ERCB's

Bitumen Recovery Technologies

The mining plants are integrated mining/upgrading operations where bituminous sand mined from open pits is separated into bitumen and sand using a hot water process. The bitumen is then upgraded to a synthetic light crude oil by refinery processes.

The in situ operations take place in areas where the overburden is too thick to allow surface mining, but thick enough to withstand the pressure of injected fluids. In such areas, steam is injected through wells to increase the temperature of the deposit and reduce the viscosity of the bitumen. Crude bitumen can then flow to a wellbore and be pumped to the surface. This in situ recovery process has been successfully implemented at several commercial projects. There are also a large number of experimental projects in operation where recovery techniques are tested before commercial projects are considered.

In situ recovery processes are being used in all three of Canada's bitumen areas (Athabasca, Cold Lake and Peace River). However, the majority of commercial in situ production is from the Cold Lake deposit, located 200 kilometres northeast of Edmonton. The bitumen viscosity in this deposit is low enough to allow effective steam injection with vertical wells. Bitumen is also produced commercially from the Peace River area, some 200 km northwest of Edmonton. Here steam is injected into a thin water bearing zone underlying the bitumen from which it gradually moves upward, contacting a large portion of the reservoir. No bitumen is currently being produced commercially by the in situ process from the Athabasca deposit, although a number of experimental and commercial projects are in operation. Some of these projects produce bitumen by primary means while other projects employ steam injection. Some of these emerging technologies are desribed below.

Steam-Assisted Gravity Drainage (SAGD) is an in-situ recovery scheme that allows extraction of bitumen from deposits located too deep for surface mining. The scheme could provide an alternative supply for stand-alone upgraders, refinery upgraders or for the integrated mining plants which currently use bitumen produced by surface mining and warm water extraction. SAGD has been successfully tested at AOSTRA's Underground Test Facility (UTF) since 1987. The technique entails drilling pairs of horizontal wells (from underground tunnels or from the surface) one about five metres above

the other, near the bottom of the oilsands formation. Steam is initially injected through both wells in order to reduce viscosity of bitumen and enhance flow between the wells. Bitumen and condensed steam are subsequently produced from the lower well, while steam continues to be injected through the upper well. The process is expected to reduce costs by at least $2 per barrel, as the adverse impact of higher front-end capital costs is more than offset by lower operating costs. Additional advantages include elimination of fine tails and simplification of post-mining reclamation.

An *enhanced* SAGD process (ESAGD) is currently being tested by Shell Canada at its Cadotte Lake demonstration project. This process may boost recovery to as high as 80 percent through the application of pressure differential between adjacent well pairs. Steam injection at Cadotte Lake started in November 1993, and the first indications of the project's production performance are expected by mid-1994. SAGD may also be combined with conventional steam drive using vertical wells for steam injection, resulting in a hybrid process which Amoco Canada labelled as Combined Drive Drainage. The company plans to convert its Wolf Lake and Primrose projects to this new process in the near future. The conversion is expected to triple the recovery factor to 50 percent and cut unit capital costs roughly in half. Similar improvements from the application of the SAGD-type processes are currently achieved in conventional heavy oil pools such as Tangleflags.

Vaporized Extraction (VAPEX) is currently in the early stages of investigation and may replace the thermal processes presently used for recovering heavy oil and bitumen. The process is similar to the SAGD process, but uses a vaporized hydrocarbon solvent rather than steam to reduce the viscosity of the crude oil in the reservoir. The main advantages claimed for the process include: high energy efficiency and negligible heat loss, low effluent handling and related environmental hazards, and in situ upgrading of oil.

AOSTRA *Taciuk Process* (ATP) is a system developed by AOSTRA for simultaneous extraction and primary upgrading of bitumen by thermal retorting of mined oilsands. The system uses a single processor that combines the equivalent functions of hot or cold water extraction, froth treatment, tails, naphtha and diluent recovery, and primary upgrading. The effect of lower liquid yield, in comparison with mining plants, is compensated for by the elimination of capital costs associated with extraction and froth treatment plants. AOSTRA claims that the net effect may be a $5 per barrel reduction in total supply cost compared to a conventional dry mining, hot water extraction process. The process may allow smaller-scale developments at reasonable costs in contrast with huge capital outlays required by large integrated plants.

Counter-Current Drum Separation (CCDS) is a commonly used mineral extraction method which Bitmin Resources Ltd. has applied experimentally to separate bitumen from oilsands. The process extracts the same volume of bitumen as conventional processes using steam and caustic soda, but uses two-thirds less water and only half the energy. Moreover, CCDS produces less heavy sludge tailings and does not require chemical additives. Bitmin claims that CCDS may cut operating costs associated with bitumen extraction from around $11 per barrel incurred at existing Suncor and Syncrude plants to as low as $6 per barrel. The company is currently making plans to build a 10 thousand cubic metres per day commercial facility in northern Alberta at a cost of $500 million. Bitmin claims that the project should be economically feasible at an oil price of around $17.

Hydrotransport entails emulsification of oilsands with water which would facilitate both the transportation of oilsands to the plant and the extraction of bitumen. The process has been successfully tested by Syncrude in a pilot project, and appears to be an improvement over current surface mining and extraction processes. Preliminary research suggests that this new technology may enhance economic viability of new surface-mining schemes, and allow extension of existing operations well beyond the present 5-kilometre radius.

Sand Reduction Technology (SRT) is a technology being developed by Canadian Occidental Petroleum Ltd., which aims at removing 90 percent of solids at the mine site using a low-temperature separation process and emulsifying bitumen for transport. The main advantage of this process would be to reduce transportation costs in the integrated mining facilities, potentially offering even greater advantages than hydrotransport. Total operating costs are expected to drop by up to $4 per barrel compared to the OSLO design. One drawback of SRT is that bitumen produced using the technology could not be handled by the existing upgraders. It could, however, be upgraded using DUT – a process currently being researched by Canmet and designed specifically for that purpose.

Direct Upgrading Technology (DUT) is a technology being developed in conjunction with SRT to allow direct upgrading of the bitumen produced by SRT. The bitumen emulsion produced with SRT at the mine site contains a considerable amount of solids and can not be used directly by standard upgrading processes. The DUT process would upgrade this emulsion to a low quality, low value synthetic crude oil which can then be shipped by pipeline to the refineries for further refining and processing. The SRT/DUT process is expected to be more economic than the established processes, as lower value of its synthetic oil product is more than offset by lower supply costs.

approval of a higher annual production ceiling of 12.5 million cubic metres.

In the same vein, operating costs for the proposed OSLO oilsands project are expected to fall from the current estimate of $17 presently to around $12. This reduction would be achieved mainly through the application of a new high conversion hydrogen-addition upgrading technology. As a means of reducing projected supply costs, the group has considered decoupling of the bitumen upgrader from the mining operation, and moving it closer to Fort McMurray or to Edmonton. Some of the new emerging technologies, such as CCDS, Hydrotransport, or SRT, could also be applied at OSLO or other similar projects, resulting in significantly lower capital costs by the late 1990s. These technologies are discussed in more detail in "Oilsands Recovery Technologies" inset.

In summary, the supply costs for Alberta's oilsands remain high relative to conventional oil, and are comparable to those for frontier oil. However, other considerations may tend to give the oilsands projects a competitive edge over frontier projects. These include a larger, better defined and more accessible reserves base, and a greater potential for future cost reductions through the application of new bitumen extraction and upgrading techniques. Potential future environmental costs may be another important consideration in assessing the costs of developing either of these resources. These costs may not be fully reflected in current estimates.

7.5.3 Projected Field Supply

Our bitumen supply projections are based on the comparison of estimated supply costs with the expected bitumen prices at the wellhead. These prices are derived from the implied heavy oil prices based on an assumed average diluent content of 38 percent (section 7.7.3) and diluent prices at par with light oil prices (Table A7-1). The derivation of heavy oil prices was explained in section 7.3.3.

Bitumen can be produced from either in situ or integrated mining projects. The latter use bitumen only as an intermediate product in production of synthetic oil. The volumes of this intermediate product are not included in bitumen supply because they are converted to and reported as synthetic oil supply.

The supply of **in situ bitumen** in the Current Tech case approximately doubles by the year 2000 from the 1993 level of 21.4 thousand cubic metres per day, mainly as a result of planned expansions of existing thermal projects such as Esso's Cold Lake, Amoco's Primrose and Wolf Lake, and Shell's Peace River projects (Figure 7-17). Beyond 2000, bitumen supply declines marginally, as further expansions of thermal projects become uneconomic due to the rising cost of steam generation, related to projected higher natural gas prices. In the High Tech case, supply continues to expand throughout the projection period and, by 2010, reaches 76.4 thousand cubic metres per day, which is more than triple the present level. The bulk of the incremental supply compared to the Current Tech case comes from unidentified thermal projects and from new primary

FIGURE 7-17

Supply of Crude Bitumen – In Situ Projects

Source: Appendix Table A7-10
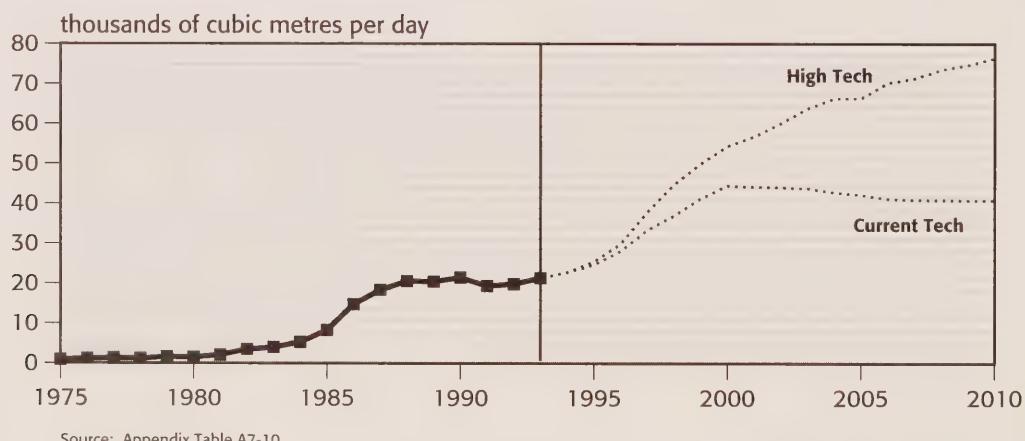
recovery projects located mainly in the Athabasca region (i.e., Koch's Reita Lake development).

Based on these anticipated production rates, reserves additions of bitumen are estimated at 350 million cubic metres for the Current Tech case and 600 million cubic metres for the High Tech case.

With regard to **integrated mining plants**, we assume in both cases that no new plants are built and that further modest increases in synthetic oil supply come entirely from debottlenecking of the existing Syncrude and Suncor plants (Figure 7-18). As a result, total supply increases over the projection period from the present level of 38.9 thousand cubic metres per day to 58.0 thousand cubic metres per day in the Current Tech case and to 62.5 thousand cubic metres per day in the High Tech case.

Reserves for the existing mining plants will be maintained through the acquisitions of new leases. Suncor is currently evaluating two leases which, in our estimate, could provide about 80 million cubic metres of reserves additions. The Syncrude plant has sufficient reserves on its current lease to continue operations through 2010. However, it is possible that alternative sources of bitumen could be developed at a lower cost, which could add 100 to 200 million cubic metres to the existing reserves base. Although these reserves additions could be exploited by either in situ or mining operations, we have added a nominal volume of 150 million cubic metres to mineable reserves in both cases.

7.6   PENTANES PLUS

This section discusses projected field supply for pentanes plus in the WCSB. The orientation of this aspect within the overall analytical framework is illustrated by the diagram in Figure 7-1.

In addition to four major supply categories described above, total Canadian supply of crude oil and equivalent also includes **pentanes plus**. Supply projections of this natural gas liquid are more fully discussed in Chapter 8. However, because pentanes plus is used nearly exclusively as a refinery feedstock, either directly or as a component of the heavy oil blend, its supply is included as a component of crude oil and equivalent supply. Table A7-10 shows the total pentanes plus supply, including field condensate, that is available as a feedstock. A small volume of production, although included in the supply of pentanes plus in Chapter 8, is not included in the supply of crude oil and equivalent because it is part of a liquid mix that is reinjected into miscible flood projects. A similar logic is applied to pentanes plus produced from frontier natural gas fields, in that the production is included in our projections only if it is shipped to the markets. Hibernia will not produce pentanes plus as such, although the stabilized crude oil that will be shipped to the markets may contain some lighter components.

Supply of pentanes plus is projected to rise in the Current Tech case from the current level of 22 thousand cubic metres per day to a peak of 29 thousand cubic metres per day in 2006, before declining to 26 thousand cubic metres per day by 2010 (Figure 7-19). In the High Tech case, the supply is expected to plateau at around 24 thousand cubic metres per day until the year 2002, and then increase rapidly to 29 thousand cubic metres per day in 2010. These projections reflect natural gas supplies anticipated in the two cases.

FIGURE 7-18

Supply of Synthetic Crude Oil from Mining Plants

Source: Appendix Table A7-10
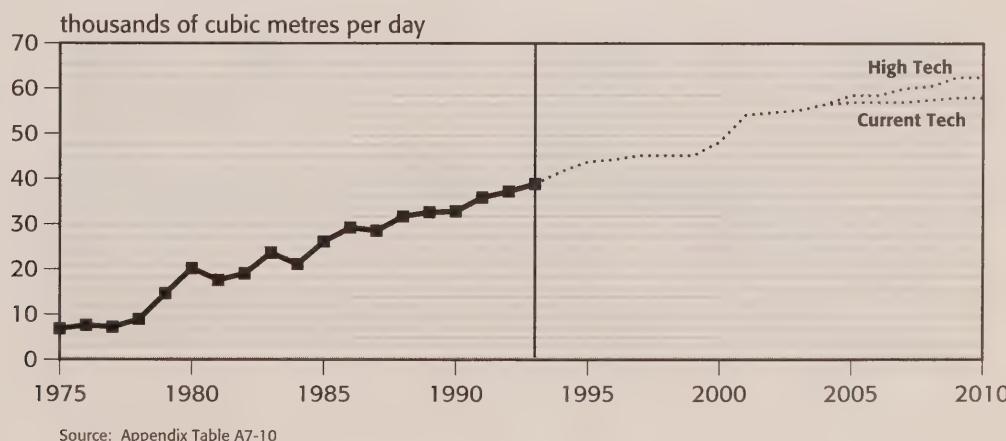
7.7 SUMMARY OF TOTAL OIL SUPPLY

7.7.1 Field Supply – Technology Cases

Estimated total reserves additions of conventional light and heavy crude oil and bitumen over the projection period for the two cases are compared with established reserves and cumulative production at year-end 1992 in Figure 7-20. In the Current Tech case, conventional light crude additions total 559 million cubic metres, which is slightly more than the remaining established reserves of 525 million cubic metres. In the High Tech case, light crude additions total 681 million cubic metres over the projection period. For conventional heavy crude oil, additions total 343 million cubic metres in the Current Tech case, which is more than double the remaining established reserves of 165 million cubic metres. In the High Tech case, heavy crude additions total 407 million cubic metres over the projection period. Bitumen reserves additions total 500 million cubic metres in the Current Tech case, roughly equal to the remaining established reserves, and 750 million cubic metres in the High Tech case. Projections of reserves

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FIGURE 7-19

Supply of Pentanes Plus

Source: Appendix Table A7-10
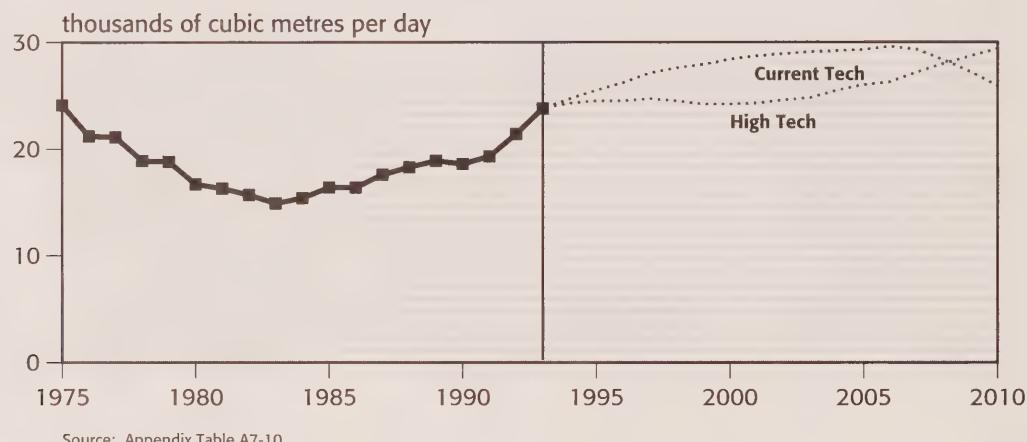
FIGURE 7-20

Remaining Reserves, Reserves Additions and Cumulative Production

(millions of cubic metres)
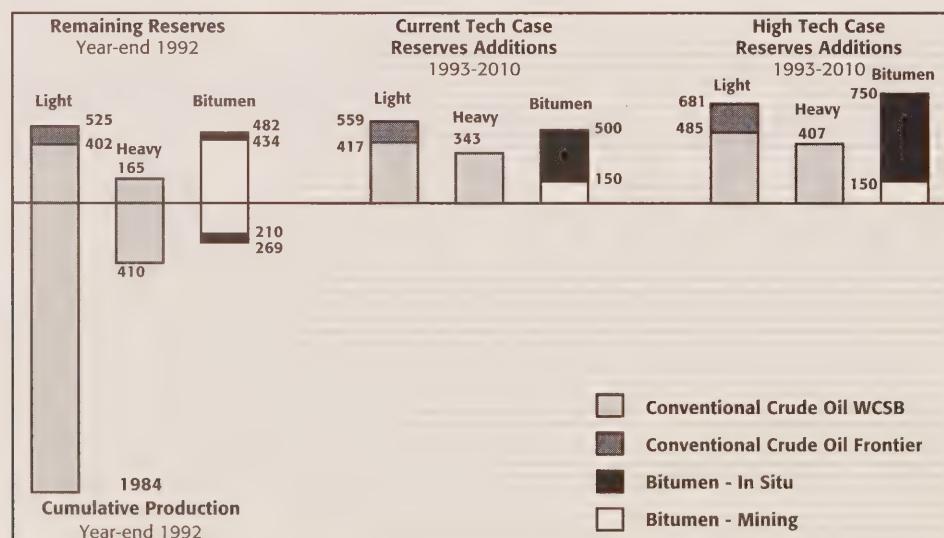
additions were also developed for the Low and High Price sensitivity cases. These are shown in Tables A7-12 and A7-13 for light and heavy oil respectively.

Projected supply of Canadian crude oil and equivalent is shown by component in Figure 7-21 for the two cases. In the **Current Tech case**, total crude oil supply peaks at about 352 thousand cubic metres per day in 1999, some 19 percent above the current level. Subsequently, supply falls gradually to 281 thousand cubic metres by 2010, only marginally below the current level. The crude oil mix becomes slightly heavier over the projection period as the share of conventional heavy oil and bitumen increases from 29 percent in 1993 to 32 percent in 2010. Supply of bitumen increases while the supply of heavy oil begins to decline after 1997. The make-up of the light oil and equivalent category changes dramatically, as a decline in conventional light oil from the WCSB is largely offset by new offshore supplies from the east coast and, to a lesser extent, by additional volumes of synthetic oil and pentanes plus.

In the **High Tech case**, total crude oil supply increases by nearly one-third by 2001, before falling gradually to 358 thousand cubic metres per day in 2010, a level that is 22 percent above the 1993 level. The shift towards heavy oil is even more pronounced than in the Current Tech case as the supply of conventional heavy oil and bitumen grows to 39 percent of total supply in 2010. Within this combined heavy oil category, supply

FIGURE 7-21

Total Supply of Crude Oil and Equivalent

Current Tech Case
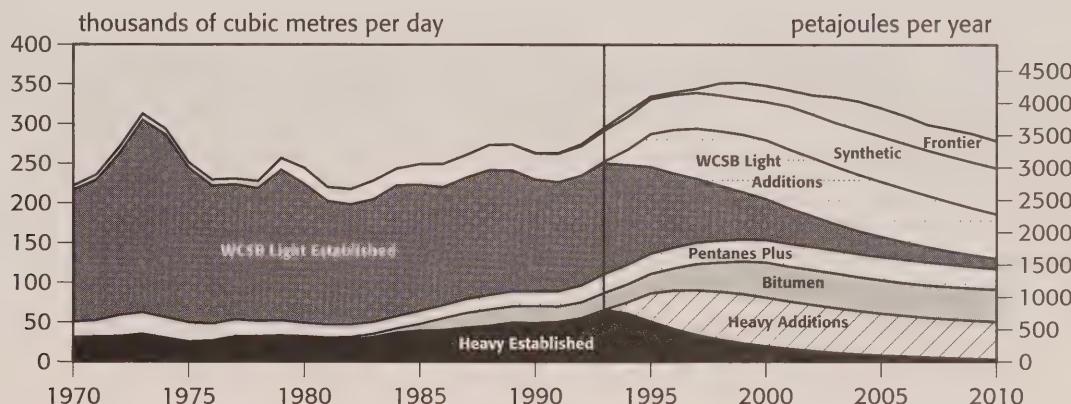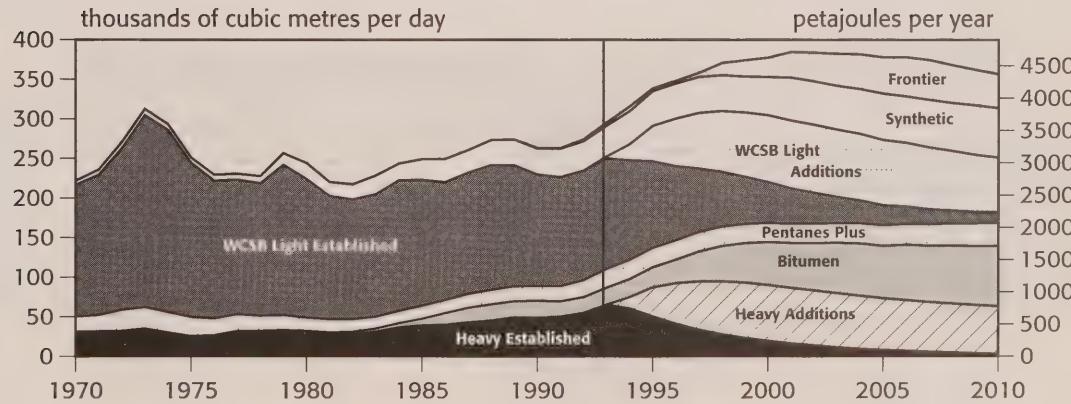
High Tech Case

Source: Appendix Table A7-10

of bitumen surpasses the supply of conventional heavy oil by 2007. The make-up of total light oil and equivalent changes in a similar manner as in the Current Tech case. More specifically, the share of conventional oil from the WCSB in total light oil supply falls from 68 percent in 1993 to just 38 percent in 2010.

The shift away from conventional crude oil sources in the WCSB is further illustrated in Figure 7-22. By the end of the projection period, the share of these traditional sources is expected to decline from the present 70 percent to 42 percent in the Current Tech case and 41 percent in the High Tech case. This decline will be accompanied by increasing contributions from east coast offshore and from Alberta's oilsands areas.

Our projections of total oil supply reflect the impact of technological progress on future production. This impact is reflected in reduced costs of exploitation of resources, larger recoverable resources and, consequently, higher supply at given prices. For conventional crude oil resources, where the ultimate resource is a constraint within the projection period, technological progress becomes particularly critical. The impact of this progress is to accelerate depletion of the resource, resulting in increased supply in the near term and faster decline in supply over the longer term.

7.7.2   Field Supply – Price Sensitivity Cases

The price sensitivity cases of US$15 and US$30 use the Current Tech case as the base case for comparison. The supply projections for these two cases are shown by component in Table A7-14.

In the **Low Price sensitivity** case, supply of conventional light oil from the WCSB declines after 1995 at an average annual rate of 7.2 thousand cubic metres per day (nearly 8 percent) compared to a decline of only 5.4 thousand cubic metres per day (5 percent) in the Current Tech case. Supply of conventional heavy oil from the WCSB declines at an average annual rate of 4 thousand cubic metres per day (8.5 percent) compared to a decline of only 2.4 thousand cubic metres per day (3.5 percent) in the Current Tech case. In the frontier, aside from a planned modest expansion of Norman Wells, Hibernia is the only major source of supply after 1997 as all other projects become unattractive. Ontario's production declines faster and ceases by around 2006, as the province's stripper wells become uneconomic.

Bitumen prices fall below the estimated supply costs for the Current Tech case, which not only forestalls the planning of new projects but also leads to the cancellation of planned expansions of existing projects. Supply from existing projects declines at 10 percent annually to 5.8 thousand cubic metres per day in 2010. With regard to synthetic oil supply, we expect in this case that: (a) no new upgraders will be added at Edmonton, (b) the second phase of Syncrude's expansion will not proceed, and (c) the Co-op upgrader may be shut down around 2004 because the light/heavy differentials are too narrow to cover the costs of upgrading.

Total supply increases slightly through 1995, before going into a steep decline. This decline brings oil supply down to just half of the 1993 level by the year 2010 (Figure 7-23).

FIGURE 7-22
Changing Composition of Canadian Oil Supply

Actual – 1993

Current Tech – 2010
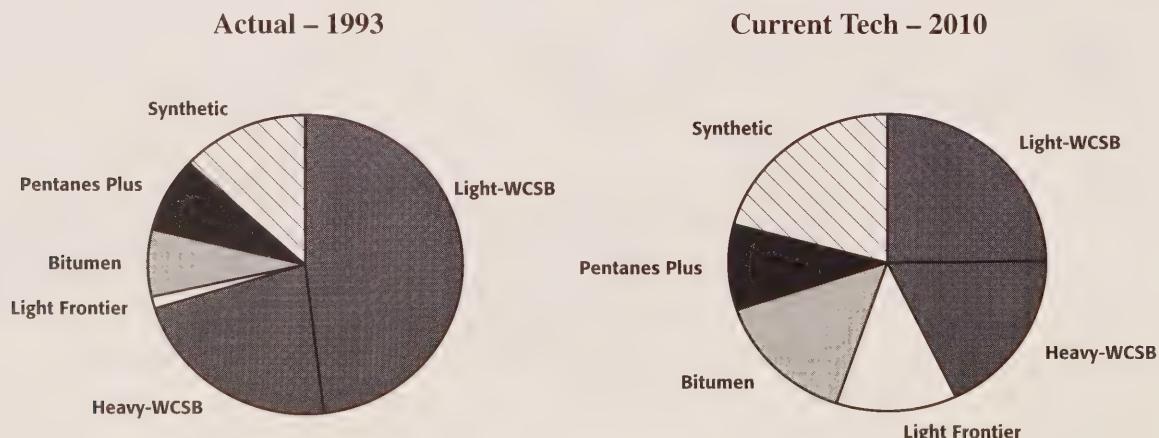
In the **High Price sensitivity** case, conventional light oil production from the WCSB declines at an average annual rate of only 3.6 thousand cubic metres per day (2.8 percent) compared to a decline of 5.4 thousand cubic metres per day (5 percent) in the Current Tech case. Supply of conventional heavy oil from the WCSB continues to increase through 1999, before falling marginally below the present level by 2010. Frontier supply is essentially the same as in the High Tech case which, compared to the Current Tech case, projects the earlier start-ups for Terra Nova and other east coast offshore projects and includes supply from the Amauligak project starting in 2006.

Supply of bitumen shows a steady growth to around 105 thousand cubic metres per day in 2010, which exceeds not only the projection in the Current Tech case but also the projections in the High Tech case. The additional volumes compared to the High Tech case come mainly from new primary recovery projects and from expansions of existing in situ steam projects, such as Shell's Peace River and Pan-Canadian's Lindbergh schemes. Synthetic crude oil supply also exceeds the levels projected in both the Current and High Tech case. The main sources of incremental supply compared to the High Tech case are a green-fields upgrader coming on stream in 2003 and a new OSLO-type integrated mining plant starting production in 2006. In addition, small incremental volumes come from further expansions of the Syncrude, Suncor and Lloydminster plants.

Total crude oil supply follows a consistent upward trend throughout the projection period. Consequently, the supply in year 2010 is 46 percent above the level projected in the Current Tech case, and 15 percent above the level projected in the High Tech case.

Figure 7-23 illustrates the supply range established by the above Low and High Price supply projections in comparison with the range projected in our 1991 Report. The comparison reveals that the new projections are more optimistic for the near term. This reflects mainly the positive impact of recent rationalization efforts and technological improvements, such as horizontal drilling, on supply costs and well production profiles. However, the two sets of projections converge toward the end of the forecast period because they are subject to similar resource constraints.

7.7.3 Blending and Upgrading

This section discusses the blending and upgrading processes which transform a large portion of conventional heavy crude oil and bitumen supply into a higher quality feedstock available to the refiners. The orientation of this aspect within the overall analytical framework is illustrated by the diagram in Figure 7-1.

Qualities of crude oil produced in Canada vary significantly across regions and geological formations. In our analysis we focus on quality differences between typical light and heavy crude oil streams. Heavy crude oil is more difficult to market because many refineries are not equipped to process this type of crude oil. Also, some conventional heavy oil streams and all of the bitumen streams are blended, normally with pentanes plus, to reduce their viscosities to pipeline specifications. **Blending** requirements are determined by the viscosity of heavy crude oils and reach up to 40 percent of blended

FIGURE 7-23

Comparison of Total Supply Ranges – Low and High Price Sensitivity Cases (Current Tech)
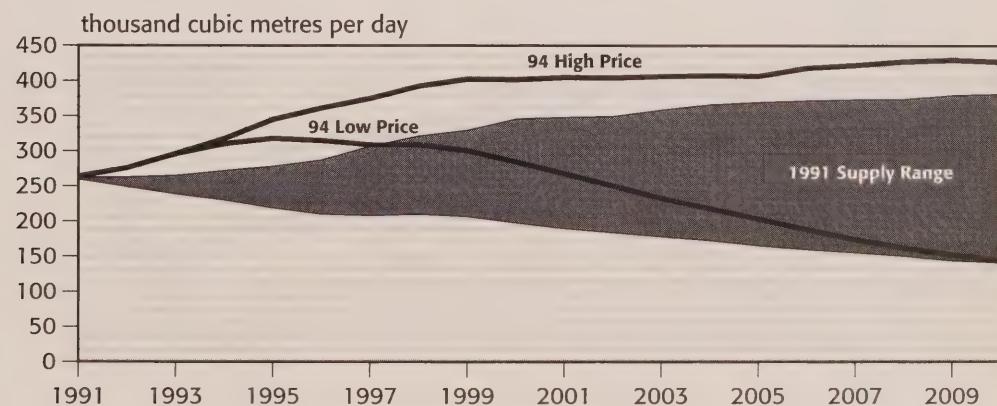
volume for the lowest-gravity conventional heavy oil and bitumen streams. This blending requirement and lower yields of higher-value products result in price discounts for heavy oil blends compared with light crude oil. When these price discounts increase due to oversupply of heavy crudes, it may become profitable to upgrade heavy oil to a lighter synthetic oil. Table A7-10 shows how various field supply components are recombined into light and heavy crude oil streams delivered at the refinery gate by taking into account blending and upgrading.

All diluent requirements can currently be met by pentanes plus, with enough remaining to meet other requirements. These include the demand by the Bowden refinery in Alberta (900 cubic metre per day) and by the shippers who use pentanes plus to reduce the vapour pressure of lighter natural gas liquids to pipeline specifications (1 200 cubic metres per day). Also, there are certain sources of pentanes plus supply that are unsuitable for blending. When the demand for diluent surpasses readily available supply of pentanes plus, prices for this commodity increase which, in turn, tends to reduce other uses of pentanes plus and makes more supply available for blending. With increasing supply of heavy crude oil and bitumen, the demand for diluent is expected to increase. This increased demand will have to compete with the non-blending requirements.

Our projections in the Current Tech case do not indicate any problems of meeting diluent requirements with pentanes plus. However, in the High Tech case net diluent demand is expected to exceed total pentanes plus supply during the period of 1999 to 2007. This situation could be remedied through increased upgrading capacity, more recycling of diluent or the use of alternative blending materials such as light crude oil fractions or naphtha. We have not investigated the merits of these options, but have assumed that diluent requirements will be met. This is reflected in Table A7-10 where the shortfall of pentanes plus for blending purposes reduces the total volume of available supply of light crude oil and equivalent.

Blended heavy crude oil and blended bitumen can be sold as is or upgraded to synthetic crude oil in **stand-alone upgraders**. Upgrading becomes attractive when crude oil differentials exceed the cost of upgrading. The process is similar to that used for producing synthetic crude oil in the integrated mining plants (discussed in section 7.5) except that the stand-alone upgraders can access more supply sources. The first stand-alone upgrader (Newgrade) was built in 1988 beside the Co-op refinery in Regina. This upgrader uses Fosterton and Lloydminster crudes as feedstock and currently produces

about 7 400 cubic metres of synthetic oil per day. The Lloydminster upgrader came on stream in 1992 and is operated by Husky Oil Limited. This upgrader uses a blend of Cold Lake bitumen and Lloydminster conventional heavy oil and produces about 7 500 cubic metres of synthetic oil per day. One advantage of upgrading heavy crude oil at Lloydminster is that the pentanes plus used as a diluent can be recycled to the adjacent producing areas. The volumes of diluent that are recycled for blending purposes are also shown in Table A7-10 for the two technology cases.

Whether new stand-alone upgraders will be constructed will depend on the supply cost of upgrading and future price differentials. Our estimates indicate that upgrading costs for the Current Tech case are in the range of $14 to $16. If we add this required price differential to an estimated delivered supply cost to the upgrader of $11 to $14, crude oil prices would have to range between $25 and $30 to ensure the economic viability of new upgraders. In the High Tech case, this price range could fall to $22-25 due mainly to an expected reduction in bitumen extraction costs.

7.7.4 Available Refinery Supply

This section summarizes our projections of crude oil supply available to the refiners in the Current and High Tech cases. The orientation of this aspect within the overall analytical framework is illustrated by the diagram in Figure 7-1.

Our projections of available crude oil supply for the Current Tech case assume that the existing upgraders continue production at the current levels through the projection period and that one small upgrader (3 000 cubic metres per day) will be added to one of the Edmonton refineries. In the High Tech case, we expect that higher light/heavy differentials will trigger a 3 500 cubic metres expansion to the existing Lloydminster upgrader around the year 2002. The Co-op upgrader continues production at the current levels and four small upgraders are added at Shell's and Esso's Edmonton refineries.

We have also examined the impact of low and high oil prices on the upgrading capacity. In the US$15 price sensitivity case, the light/heavy price differentials remain very narrow, discouraging construction of any new upgraders and leading to a shutdown of the Co-op upgrader around the year 2003. In the US$30 price sensitivity case, the differentials widen dramatically, leading to an expansion of the upgrading capacity beyond that projected in the High Tech case. Additional capacity comes from the expansions of the existing two upgraders and from four new upgrading units at the

Edmonton refineries. The upgrading capacity is still insufficient to handle incremental supplies of heavy oil blends projected in this case, leading to a shortage of pentanes plus for diluent purposes. This shortage may be met by other solutions such as light crude oil or oil/water emulsion.

Since only the Current and High Tech cases are considered in the following analysis of the refinery balances, we do not discuss here the total available supplies of crude oil and equivalent developed for the Low and High Price sensitivities. These two supply profiles are summarized in Table A7-14 and are based on field production profiles discussed in section 7.7.2.

The function of the stand-alone upgraders is to produce synthetic light oil from a blended heavy oil feedstock. This processing only marginally increases the availability of total crude oil and equivalent as the addition of hydrogen is partly offset by product losses incurred during the upgrading process. The main net effect of the stand-alone upgraders is to increase the supply of light crude oil and equivalent available to the refiners at the expense of blended heavy oil. In the Current Tech case, production of synthetic oil from the stand-alone upgraders remains flat throughout the projection period at the 1993 level of about 14 thousand cubic metres per day. In the High Tech case, this volume gradually increases to 25 thousand cubic metres per day in 2010.

As a result, total light crude oil and equivalent available to refiners in the Current Tech case decreases from the 1993 level of 211 thousand cubic metres per day to 183 thousand cubic metres per day in 2010. In the High Tech case, however, this supply is maintained above the 1993 level throughout the projection period. The above volumes include frontier oil discussed in section 7.4.4.

With regard to blended heavy oil, supply available to the refiners increases in the Current Tech case from the 1993 level of 86 thousand cubic metres per day to about 135 thousand cubic metres per day in 1999, before declining to about 96 thousand cubic metres per day in 2010. In the High Tech case, this supply reaches a higher peak of 158 thousand cubic metres per day in the year 2000, and then falls to 144 thousand cubic metres per day in 2010.

7.8   REFINERY BALANCES AND OIL SUPPLY/DEMAND PROFILES

In the preceding sections of this chapter, we have described the scenarios used as a basis for our projections of light and heavy crude oil supply. In this section, we first review domestic petroleum product demands and describe the basis for our projections of product imports and exports and, subsequently, feedstock requirements. This is followed by an examination of the supply and demand balances for light and heavy crude oil, including bitumen, as well as exports and imports of crude oil and petroleum products for the Current and High Tech cases. The orientation of this aspect within the overall analytical framework is illustrated by the diagram in Figure 7-1. The closing part of this section discusses major implications of the overall supply/demand balances for Canadian refineries and pipeline systems.

Canadian refinery feedstock requirements are met from both domestic and imported crude oil supplies. Surplus domestic crude oil production is exported, primarily to the United States. The projections described in this section have been developed in the context of initially increasing and then gradually declining domestic conventional light crude oil supply, increasing availability of domestic heavy crude oil blend and modest growth in domestic demand for petroleum products described earlier in the report.

Prior to discussing refinery balances, we first describe the major crude oil pipeline systems in Canada.

7.8.1   Crude Oil Pipelines

Figure 7-24 provides an overview of the major crude oil pipeline systems and refining centres in Canada in 1993. Domestic crude oil production comes primarily from the provinces of British Columbia, Alberta, Saskatchewan, Manitoba and from the Norman Wells field in the North West Territories as well as Cohasset/Panuke. Crude oil shipments to domestic and export markets on the west coast are through the Trans Mountain Pipe Line Company Ltd. ("TMPL") system. Crude oil shipments to Eastern Canada as far as Montreal and to export markets in the Northern Tier (Midwest states and Montana) of the United States occur via the Interprovincial Pipe Line Inc. ("IPL") system. Wascana Pipe Line also ships crude oil to the Northern Tier, from IPL, and to PADD IV, while the Rangeland and Murphy pipeline systems ship crude oil to Montana.

Historically, refining centres west of Montreal obtained most of their crude oil supply from Western Canada. Until the early 1990's, Montreal refineries obtained their crude oil from both Western Canada and offshore imports via the Portland Pipeline system. In July 1991, IPL's Sarnia-to-Montreal extension was de-activated. It was re-commissioned in July 1992, following a nomination by the Alberta Petroleum

Marketing Commission to ship crude oil to Montreal. The extension was subsequently filled and small quantities of domestic crude oil have since been shipped to Montreal. Refineries east of Montreal were supplied primarily by tanker from offshore sources.

TMPL and IPL operate the two major pipeline systems through which Canadian crude oil is moved to domestic and export markets. The Portland-Montreal pipeline also plays an important role in the delivery of offshore crude oil to Montreal refineries.

TMPL operates a pipeline for the shipment of crude oil and refined petroleum products from receipt points in Alberta and British Columbia to locations in central B.C. and the Vancouver area. The Westridge marine terminal in Burnaby, B.C. is used for tanker shipments of light and heavy crude oil to offshore markets. TMPL also operates a lateral pipeline from Sumas, B.C. to Anacortes, Washington where four refineries are located. Although these refiners depend primarily on Alaskan North Slope crude oil, they take Canadian crude oil when it is priced competitively.

While crude oil historically constituted a large portion of TMPL's throughput, significant volumes of refined petroleum products (gasoline and diesel) have been delivered to product terminals at Kamloops and to Vancouver, B.C. commencing in mid-1993. On average, the pipeline shipped 33.7 thousand cubic metres per day of crude oil and products in 1993, of which 21.4 thousand cubic metres per day were for domestic consumption and 12.3 thousand cubic metres per day for export. With the closure of the Shell and Petro-Canada refineries in Vancouver, crude oil shipments to domestic refineries fell in 1993 and were replaced by deliveries of petroleum products. With the announced closure of Esso's refinery, crude oil shipments are expected to decline further to about ten thousand cubic metres per day beginning in 1995. In April 1994, the NEB approved an expansion to TMPL's system of six thousand cubic metres per day. The expansion is expected to be fully completed by the end of 1994. The expansion will accommodate higher deliveries of light crude oil to offshore markets via TMPL's Westridge dock as well as increased shipments of crude oil and condensate to Washington State refineries.

IPL operates the largest and most complex petroleum pipeline system in North America, stretching over 3 700 kilometres from Edmonton, Alberta to Montreal, Quebec. The system transports many different grades of petroleum, including petroleum products, natural gas liquids and light, medium and heavy crude oils. IPL delivers to locations in the Prairie provinces and to refining centres in Sarnia, Toronto, and Nanticoke, Ontario; Montreal, Quebec; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; the Chicago area of Illinois and Indiana; Detroit, Michigan; Toledo and Canton, Ohio; and the Buffalo, New York area.

During 1993, average throughput on the IPL system was about 233 thousand cubic metres per day, with deliveries to domestic markets at 117 thousand cubic metres per day and deliveries to export markets at 116 thousand cubic metres per day. In January 1994, the NEB approved an application by IPL to expand its capacity by 27.1 thousand cubic metres per day between Edmonton and Chicago. The expansion is expected to be completed by January 1995.

The Wascana pipeline system connects with IPL at Regina, Saskatchewan and extends south to Raymond, Montana where it connects to the Texaco pipeline, which in turn delivers crude oil through the Butte pipeline to Guernsey, Wyoming. From there, Canadian crude oil is delivered to refineries in PADD IV and PADD II. Wascana has a crude oil capacity of about seven thousand cubic metres per day. Historically, Wascana has shipped light crude oil and condensate.

The Rangeland system which commences at Sundre, Alberta ships light sweet crude oil, Cold Lake blend, condensate and butane to the Conoco pipeline at the Alberta-Montana border for delivery to Montana refineries. Rangeland has a capacity of about ten thousand cubic metres per day. At the north end of the pipeline, it is connected to the Bonnie Glen pipeline system which delivers crude oil to Edmonton.

Murphy's Milk River pipeline ships mainly heavy crude oil from southeast Alberta to the Cenex pipeline in Montana for delivery to refineries located in the state. The estimated capacity of this system is about seven thousand cubic metres per day.

The Westspur pipeline system ships light and medium crude oil from southeast Saskatchewan to IPL at Cromer, Manitoba. Westspur's current capacity is approximately 22 thousand cubic metres per day.

The Portland-Montreal pipeline transports offshore crude oil from South Portland, Maine, to Montreal, Quebec. The system currently has a capacity of about 39 thousand cubic metres per day, which compares with a Montreal refinery capacity of approximately 33 thousand cubic metres per day. The Portland pipeline could accommodate an increase in deliveries to about 60 thousand cubic metres per day, with minimal investment. Further expansion would enable Montreal refiners to import their requirements and provide Ontario refiners

with the flexibility to import significant quantities of crude oil if the Sarnia-to-Montreal pipeline were reversed.

7.8.2 Refinery Balances

To assess the implications of trends in petroleum product consumption for crude oil supply and demand, product demands must be converted to the corresponding requirements for refinery feedstocks. Important factors to account for in this regard are total product demand, available refinery capacity, product imports and exports, transportation logistics and the availability of refinery feedstock (i.e., light and heavy crude oil supply). Product demand was described in Chapter 4. In this section, we outline our assumptions regarding refinery capacity and product imports and exports, and summarize the refinery feedstock requirements for the Current and High Tech cases. The availability of feedstock is discussed in further detail in this section.

Refinery Capacity

In 1980, there were 37 refineries operating in Canada, with a combined distillation capacity of about 370 thousand cubic metres per day. Following a period of refinery rationalization, Canada's total refining capacity had stabilized at a level of about 305 thousand cubic metres per day by the end of the 1980's. Since then, there have been three additional refinery closures in B.C. and some minor expansions to other refineries. In 1993,

FIGURE 7-24

Major Crude Oil Pipelines and Canadian Refining Areas – 1993

(cubic metres per day)
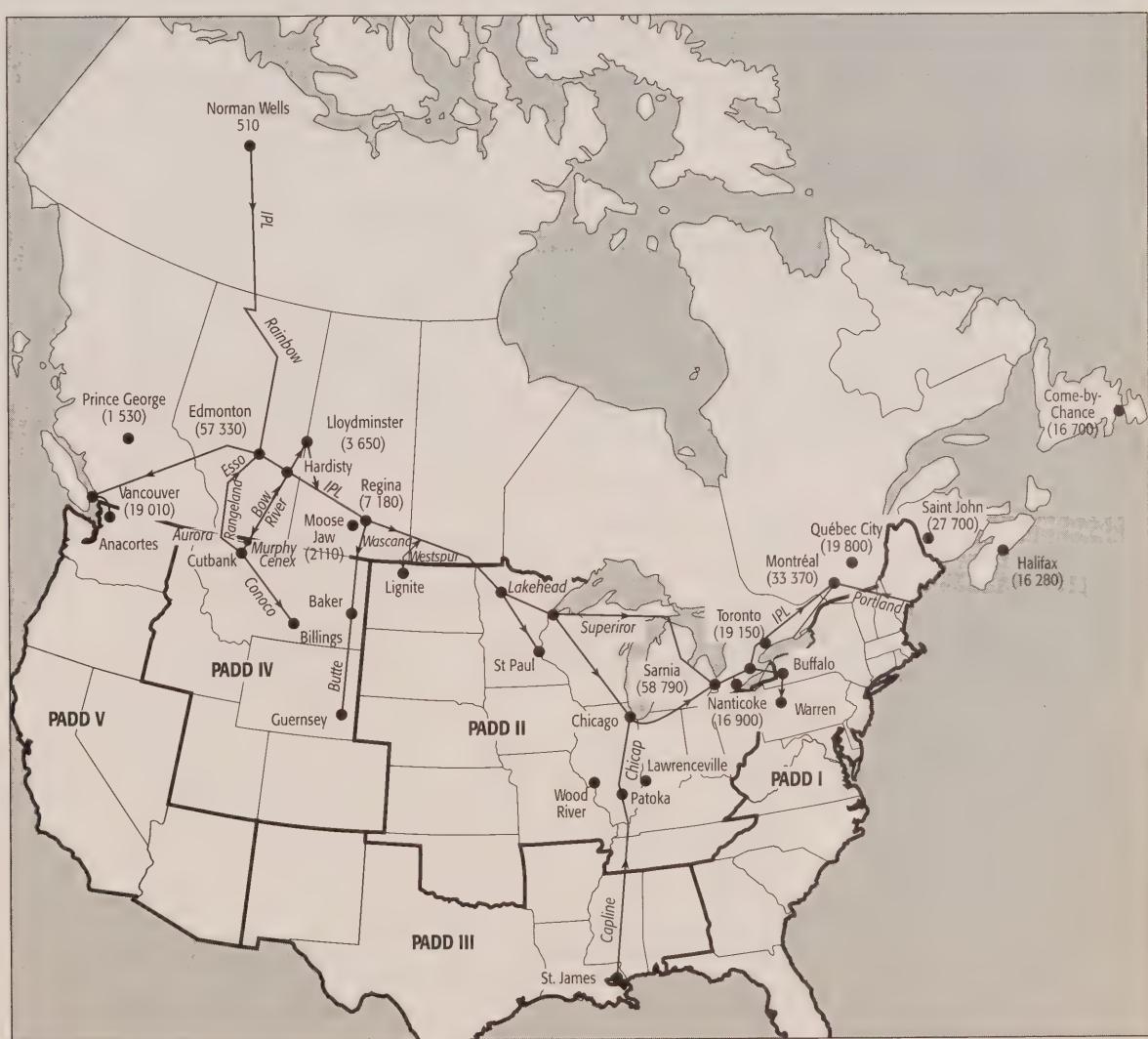
refinery capacity averaged about 300 thousand cubic metres per day (Table 7-5).

Since 1980, the refining industry has made improvements to its processing equipment to increase the production of light products such as gasolines and middle distillates. Some further improvements in product yields are expected, in order to meet changing product demands and specifications, including reduced sulphur levels in diesel fuel and improved motor gasoline quality. These changes are the result of continually more rigid product specifications, designed to bring about a reduction in emissions of lead, sulphur oxides and nitrogen oxides. Significant further capital investment will likely be required to meet these environmental standards.

The refining industry in Canada is generally highly competitive as well as capital intensive, with the consequence that margins have typically been relatively poor and profitability low. We anticipate, therefore, that the industry will likely strive to minimize its capital investment over the projection period, limiting projects to those related to environmental standards and changes necessary to meet demand for specific petroleum products.

Product Exports and Imports and Refinery Feedstock Requirements

Projections of refinery feedstock requirements (Table 7-6) were developed starting from the estimates of demand for petroleum products, and then accounting for likely levels of inter-regional transfers and anticipated imports and exports of products.

Total domestic demand for petroleum products in the Current Tech case increases from 216 thousand cubic metres per day in 1993 to 282 thousand cubic metres per day by the year 2010, an increase of 66 thousand cubic metres per day. In the High Tech case, total domestic demand for petroleum products rises to 268 thousand cubic metres per day in 2010, an increase of 52 thousand cubic metres per day from the 1993 level.

We anticipate that exports and imports of petroleum products will continue to play a role in balancing supply and demand. Our assessment is that refiners and independent marketers will export and import products during the projection period to overcome seasonal and regional imbalances in demand and to operate refineries as efficiently as possible. Furthermore, they will attempt to maintain product inventories at minimum levels.

Total exports of petroleum products averaged about 39 thousand cubic metres per day in 1993. We estimate that exports will remain at a level of about 35 thousand cubic metres per day throughout the projection period in both the Current and High Tech cases. About 60 percent of these exports will be from the Atlantic region which reflects crude oil imported under processing agreements, and the ongoing marketing opportunities that will continue to exist along the U.S. east coast.

In 1993, total imports of petroleum products averaged 22 thousand cubic metres per day. We anticipate that some large industrial consumers and utilities in Eastern Canada will continue importing HFO for their own consumption. As well, we expect independent marketers to import petroleum products on a spot basis, taking advantage of periodic low international spot prices. In the Current Tech case, we project that product imports will be 27 thousand cubic metres per day in year 2000, and then rise to 40 thousand

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TABLE 7-5

Canadian Refinery Capacities and Crude Runs – 1993

(thousands of cubic metres per day, crude oil and equivalent)

	Capacity	Crude Runs	Utilization Rate %
Atlantic Provinces	60.7	48.9	81
Quebec	53.2	46.0	86
Ontario	94.8	73.8	78
Prairie Provinces	70.8	60.3	85
British Columbia/N.W.T.	20.6	19.0	92
Total Canada	300.1	248.0	83

cubic metres per day in 2005 and to 55 thousand cubic metres per day in 2010. The rise in imports is smaller in the High Tech case; to 31 thousand cubic metres per day in 2005 and to 41 thousand cubic metres per day in 2010.

In the Current Tech case, product imports are projected to increase after 2000 in order to satisfy a growing demand for HFO in Quebec and Ontario and to meet other domestic demands, which cannot be met by domestic production because of refinery capacity limitations.

In Eastern Canada, including Ontario, crude runs are projected to increase by about 18 percent in both the Current and High Tech cases, from 169 thousand cubic metres per day in 1993 to 200 thousand cubic metres per

TABLE 7-6

Refinery Feedstock Requirements and Sources

(thousands of cubic metres per day)

Current Technology Case

	1993	1994	1995	2000	2005	2010
Demand for Petroleum Products	216	219	227	245	266	282
Product Exports	39	38	35	34	33	33
Product Imports	-22	-22	-25	-27	-40	-55
Inventory Change and Refinery Use	15	16	16	18	19	21
Refinery Feedstock Requirements	248	251	253	270	279	281
Supplied by: Crude Oil						
Light	219	215	216	232	239	240
Heavy	26	27	27	29	30	31
Total	245	242	243	261	269	271
Other[1]	3	10	10	10	10	10

High Technology Case

	1993	1994	1995	2000	2005	2010
Demand for Petroleum Products	216	218	224	238	254	268
Product Exports	39	38	35	34	33	33
Product Imports	-22	-22	-25	-26	-31	-41
Inventory Change and Refinery Use	15	16	16	17	18	19
Refinery Feedstock Requirements	248	249	250	263	275	279
Supplied by: Crude Oil						
Light	219	213	213	224	235	238
Heavy	26	27	27	29	30	31
Total	245	240	240	253	265	270
Other[1]	3	10	10	10	10	10

Notes:
1   Includes inventory change and other feedstock sources.
     The numbers in this table have been rounded.
Sources: Appendix A7-15, Tables 7-7 and 7-8.

day by 2010. In Western Canada, crude runs are anticipated to remain at a level of about 79 thousand cubic metres per day, with rises in the Prairies offset by declines in B.C., reflecting refinery closures in that province.

Based on current refinery capacities, the refinery utilization rate in the Atlantic provinces is projected to rise from 81 percent in 1993 to 83 percent by the end of the projection period. By 2010, capacity utilization reaches 100 percent in the other regions. It should be noted that refineries generally do not operate at capacity for prolonged periods, and that some debottlenecking or minor expansions could occur as refineries approach these operating levels.

Some refiners have historically made inter-regional transfers of petroleum products. During the projection period, we expect that these transfers of finished products will continue, especially between Edmonton and locations in British Columbia where a number of refineries have been or are scheduled to close. In addition, inter-regional transfers into Ontario from the Prairie provinces and Quebec will be maintained during the forecast period.

In summary, we anticipate that the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity until about 2000. Subsequently, product imports in Quebec, Ontario and British Columbia may increase somewhat from the current low levels. In particular, the rise in demand for heavy fuel oil, which occurs later in the projection period in the Current Tech case, would have to be satisfied by HFO imports into Ontario and Quebec.

7.8.3   Crude Oil Supply/Demand Profiles

In the previous sections, we outlined our assumptions regarding refinery capacity and product exports and imports necessary to satisfy domestic product demand. This section examines in more detail the relationship between refinery feedstock requirements and domestic crude oil supply, and crude oil exports and imports. It also describes the implications of our analysis for major crude oil pipeline systems.

Refineries in Canada generally use light crude oil to manufacture petroleum products, while the bulk of Canadian heavy crude oil production is exported. Thus, in order to assess the extent to which domestic feedstock demand can be satisfied from indigenous production, it is necessary to determine supply and demand balances for light and heavy crude oils separately. In this section, heavy oil refers to conventional heavy oil or the blends of either conventional heavy oil or bitumen with diluent.

Light Crude Oil

In Table 7-7, we show an outlook of supply and disposition for light crude oil and equivalent. In 1993, production was 211 thousand cubic metres per day, compared with domestic refinery demand of 219 thousand cubic metres per day. Canada exported about 77 thousand cubic metres per day of light crude oil in 1993, mainly to the Northern Tier of the United States. Figure 7-25 shows the disposition of these light crude oil exports. Imports of light crude oil to Eastern Canada, including Ontario, in 1993 were 85 thousand cubic metres per day, resulting in net imports of nine thousand cubic metres per day.

For our projection, we have assumed that Western Canadian crude oil will be used first to satisfy refinery demand in Western Canada and to maintain a certain level of exports to U.S. markets. We anticipate that market forces will result in a sustained level of light crude oil exports of at least 30 thousand cubic metres per day. Our analysis was based on an assessment of the likely crude oil acquisition intentions of U.S. buyers. It reflects our expectation that some crude oil currently shipped to U.S. refiners on the Rangeland and Murphy's Milk River pipeline systems would likely continue and that certain other U.S. refiners, which are at least partially dependent on Canadian supply, would continue to purchase Canadian crude oil.

The remaining Western Canadian light crude oil supply would then be available to satisfy the needs of Quebec and Ontario. After a brief de-activation in late 1991 and early 1992, the Sarnia-to-Montreal pipeline resumed deliveries to Montreal and it has been assumed that a small quantity of crude oil will continue to be delivered to this market through 1994. The use of domestic light crude oil supply in Canada, in the Current Tech case, is anticipated to decline from 134 thousand cubic metres per day in 1993 to 119 thousand cubic metres per day in 2010, while in the High Tech case, it is projected to increase to 142 thousand cubic metres per day in 2010.

We have assumed that most of the offshore production from the east coast would be exported (probably to the United States). Of the companies involved in the development of the Hibernia field, including Chevron Canada, Murphy Oil, Petro-Canada and Mobil, only Petro-Canada has a refinery in Eastern Canada, at Montreal. As well, because of its high paraffin content, Canadian refiners would likely have to make significant investments to be able to process this crude oil.

Light crude oil imports in 1993 of 85 thousand cubic metres per day represented about 39 percent of total light crude oil requirements. In the Current Tech case, imports are projected to increase to 121 thousand cubic metres per day by 2010, representing 50 percent of total light crude runs. In the High Tech case, imports rise to only 97 thousand cubic metres per day by 2010, comprising 41 percent of total light crude runs. Some of this growth in imports in the Current Tech case is projected to occur in Ontario.

Heavy Crude Oil

In the Current Tech case, available supply of blended heavy crude oil increases from 86 thousand cubic metres per day in 1993 to 134 thousand cubic metres per day in 2000 primarily as a result of an increase in bitumen production, and then declines to 96 thousand cubic metres per day by 2010. In the High Tech case, blended heavy crude oil supply rises to 158 thousand cubic metres per day by 2000 and then drops to 144 thousand cubic metres per day by 2010. As has been the case for many years, available supply exceeds domestic requirements throughout the projection period (Table 7-8).

The Canadian refineries that rely on domestic crude oil were, for the most part, designed to process light sweet crude oil, and only limited volumes of heavy crude oil are used during the summer for the manufacture of asphalt. It is unlikely that Canadian refineries will significantly increase their use of heavy crude oil, unless

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TABLE 7-7

Supply and Disposition of Light Crude Oil and Equivalent

(thousands of cubic metres per day)

Current Technology Case						
	1993	**1994**	**1995**	**2000**	**2005**	**2010**
Domestic Supply[1]	211	217	222	215	211	183
Imports	85	82	84	89	97	121
Total Supply	296	299	306	304	308	304
Total Domestic Requirements	219	215	216	232	239	240
Exports	77	85	90	72	69	64
Total Disposition	296	299	306	304	308	304
Net Imports	9	-3	-6	17	28	56
High Technology Case						
	1993	**1994**	**1995**	**2000**	**2005**	**2010**
Domestic Supply[1]	211	218	224	220	230	215
Imports	85	81	83	87	93	97
Total Supply	296	299	307	307	322	311
Total Domestic Requirements	219	213	213	224	235	238
Exports	77	87	94	83	88	73
Total Disposition	296	299	307	307	322	311
Net Imports	9	-5	-11	5	5	24

Notes:
1   Domestic supply is net of diluent requirements for heavy crude oil.
    The numbers in this table have been rounded.

Sources: Appendix Table A7-16 and Table 7-9.

the light/heavy oil price differentials widen sufficiently to justify large capital expenditures associated with the construction of the necessary processing facilities.

As discussed previously, the price differentials in the Current Tech case are expected to increase only marginally through the forecast period. At these differentials, U.S. refineries can expand existing heavy oil upgrading facilities at a marginal cost below that which would be required by Canadian refineries not having existing upgrading facilities. In the High Tech case, the differentials are projected to widen substantially, providing additional incentive for U.S. refineries to expand upgrading facilities. In this case, the supply projection already accounts for some upgrading in Edmonton later in the period when price differentials between light and heavy crude oil are assumed to widen significantly as a consequence of the growing production of bitumen. However, investment in such upgrading projects is expected to remain highly uncertain and alternative markets for heavy crude oil may have to be found if these projects do not materialize.

The estimated domestic requirements for heavy crude oil, excluding upgrader feedstock, are projected to increase from 26 thousand cubic metres per day in 1993 to 31 thousand cubic metres per day in 2010. Seven thousand cubic metres per day is currently imported by refineries in Quebec and the Atlantic Provinces; this level of imports is expected to continue during the projection period for use in the production of such products as asphalt. Domestic demand for heavy crude oil as a proportion of total crude oil requirements remains constant at roughly 11 percent throughout the projection period.

Canada currently exports the bulk of its heavy crude oil production, primarily to the United States. Figure 7-26 identifies the main locations to which Canadian heavy crude oil was exported in 1993. The major U.S. market is the Northern Tier.

With regard to the outlook for the export market potential for Canadian heavy crude oil, we have developed our projection using an approach which took account of factors such as current and expected trade

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FIGURE 7-25

Estimated Exports and Imports of Light Crude Oil by Market – 1993

(thousands of cubic metres per day)
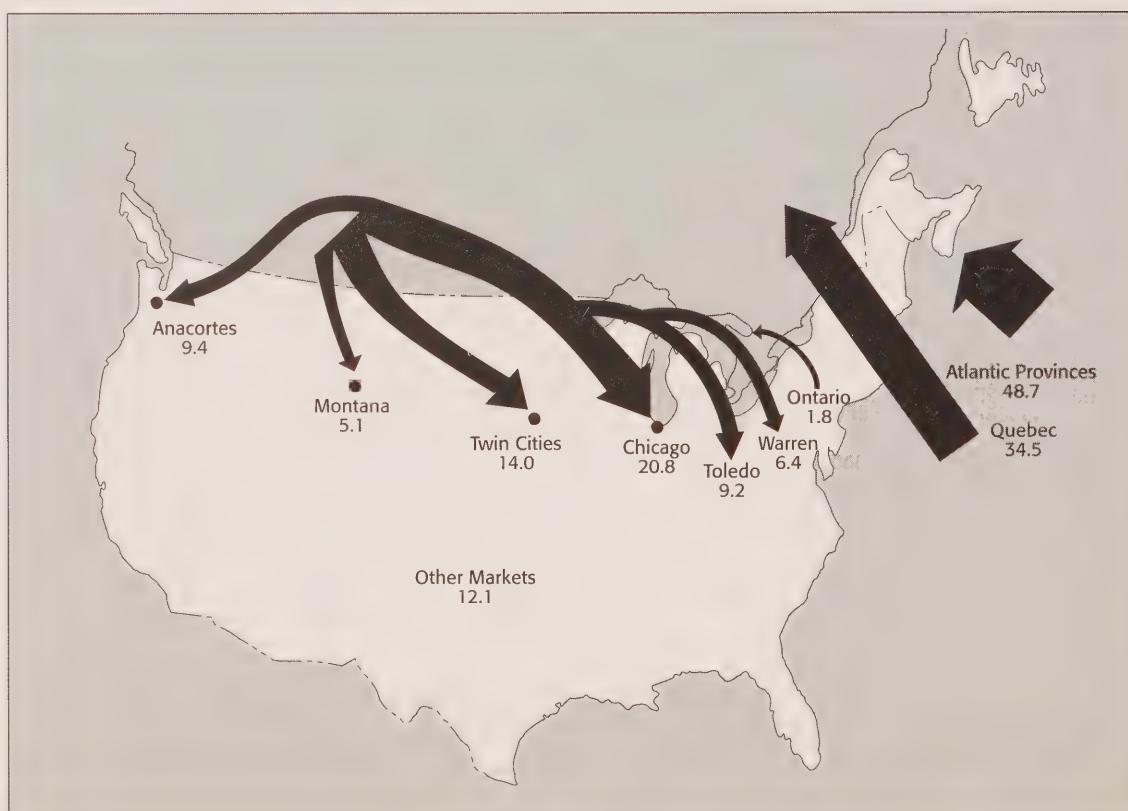
patterns for Canadian heavy crude oil, scope for the development of new markets and the current intentions of U.S. refiners to undertake upgrading investments. Specifically, our projection of the U.S. market for Canadian heavy crude oil is based on the following considerations:

- We do not expect major changes in U.S. product demand in the Northern Tier area served by Canadian heavy crude oil over the projection period;

- U.S. indigenous production currently supplying refineries in the Northern Tier is declining, particularly for Wyoming sour crudes, providing an opportunity for Canadian heavy crudes to capture additional market share;

- The refining capacity for heavy crudes in the Northern Tier has the potential for expansion at costs consistent with the lower end of the range of differentials that we are using. This is in contrast to the situation in Canada where refiners, for the most part, have not made these investments over the years, preferring instead to rely on adequate supplies of light sweet crude oil. Because U.S. refiners began an upgrading program some years ago, incremental refinery upgrading is much less costly than in Canada;

- U.S. refiners have indicated an intention to significantly increase utilization of these crude oils, which would provide a potential for further market penetration by Canadian suppliers; and

TABLE 7-8

Supply and Disposition of Heavy Crude Oil

(thousands of cubic metres per day)

Current Technology Case	1993	1994	1995	2000	2005	2010
Domestic Supply[1]	86	98	113	134	109	96
Imports	7	7	7	7	7	7
Total Supply	93	105	120	141	116	103
Total Domestic Requirements	26	27	27	29	30	31
Exports	67	78	93	113	86	71
Total Disposition	93	105	120	141	116	103
Net Exports	60	71	86	106	79	64
High Technology Case	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Domestic Supply[1]	86	98	115	158	149	144
Imports	7	7	7	7	7	7
Total Supply	93	105	122	165	156	151
Total Domestic Requirements	26	27	27	29	30	31
Exports	67	78	95	137	126	119
Total Disposition	93	105	122	165	156	151
Net Exports	60	71	88	130	119	112

1   Domestic supply includes diluent requirements for heavy crude oil.
    The numbers in this table have been rounded.

Sources: Appendix Table A7-16 and Table 7-9.

- The existence of an established transportation infrastructure for access to these markets by Canadian heavy crude oil producers.

Taken together, these factors suggest that Canadian heavy crude oil could well play an increasing role in meeting the Northern Tier demand for feedstocks over the projection period. We recognize, however, that there will continue to be strong competitive pressures in these markets. Additionally, to the extent that upgrading projects in Western Canada do not materialize in the post-2000 period, there would have to be an even greater reliance on these markets to accommodate the growth in bitumen production, particularly in the High Tech case.

Assuming no installation of conversion capacity in Eastern Canadian refineries, the likely alternative market outlet would be Wood River. Currently, refineries in this area are able to receive small volumes of Canadian crude oil, from the Wascana pipeline and the recent reversal of Mobil's pipeline which extends south from Chicago. We have assumed that, in the High Tech case, Canadian heavy crudes will penetrate this area, although it is recognized that this is a highly competitive market, and subject to pressures from offshore imports.

Summary of Trade in Crude Oil And Petroleum Products

In 1993, Canada was a net exporter of crude oil and equivalent to the extent of 51 thousand cubic metres per day. Net imports of light crude oil of nine thousand cubic metres per day were more than offset by net exports of heavy crude oil of 60 thousand cubic metres per day. Our projections suggest that, in the Current Tech case, the net export position for total crude oil will be 88 thousand cubic metres per day in 2000, but thereafter decrease to eight thousand cubic metres per day by 2010 (Table 7-9). In the High Tech case, the net export position for total crude oil will increase to 125 thousand cubic metres per day in 2000, and then decline to 89 thousand cubic metres per day by 2010.

FIGURE 7-26

Estimated Exports and Imports of Heavy Crude Oil by Market – 1993

(thousands of cubic metres per day)
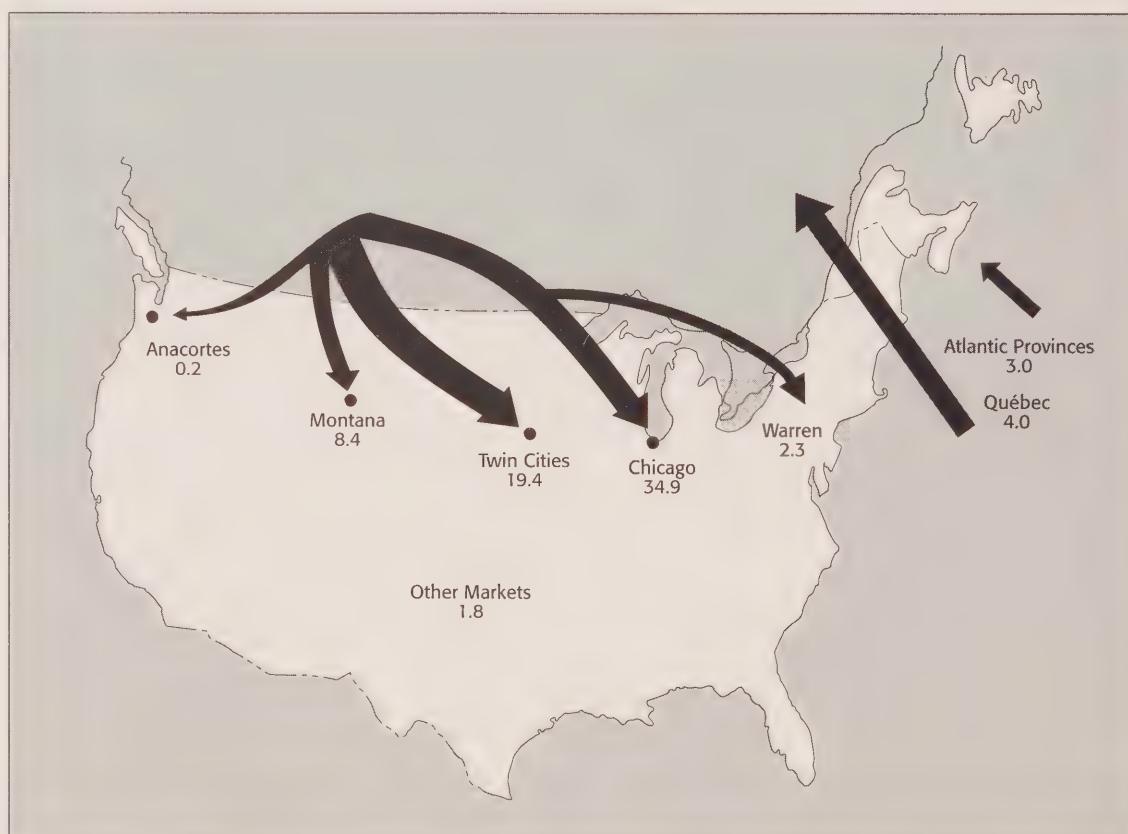
In 1993, trade in **oil products** resulted in net exports of 17 thousand cubic metres per day. It is expected that, in the Current and High Tech cases, this net export position will decline to about eight thousand cubic metres per day in 2000. By 2010, there will be net imports of 22 thousand cubic metres per day in the Current Tech case primarily reflecting the growing imports of heavy fuel oil discussed earlier. In the High Tech case, net product imports will be eight thousand cubic metres per day by 2010.

In the Current Tech case, the **overall net balance**, including crude oil and petroleum products, is projected to increase from a net export of 68 thousand cubic metres per day in 1993 to 96 thousand cubic metres per day in 2000 and then change to a net import of 14 thousand cubic metres per day by 2010. The net export position in the High Tech case peaks at 133 thousand cubic metres per day in 2000 and then declines to 81 thousand cubic metres per day by 2010.

Table 7-10 illustrates the increasing light crude oil requirements of Ontario refiners. From a level of about 58 thousand cubic metres per day in 1993, Ontario's light crude oil needs are expected to grow to approximately 74 thousand cubic metres per day by 2005. As a consequence of the declining availability of domestic light crude oil feedstocks throughout the review period in the Current Tech case, Ontario refiners could require imported supplies by about 2005. Dependence on foreign feedstocks is projected to be about 24 thousand cubic metres per day by 2010, when imports would represent nearly 32 percent of Ontario's light crude oil requirements. Ontario would not require imported supplies in the High Tech case until about 2010 as there would be sufficient domestic light crude oil feedstocks.

The major factors influencing the timing of the demand for imported feedstock supplies in Ontario include the growth in petroleum product consumption, the decline in domestic light crude oil supply, the relative prices of competing crude oils and the level of continuing light crude oil exports.

Ontario's growing light crude oil requirements could be met by increased imports through the Portland-Montreal pipeline system, in conjunction with a reversal of the Sarnia-to-Montreal pipeline. Alternatively, limited volumes of foreign crude oil could be shipped from the U.S. Gulf Coast to Chicago and then to Ontario, although this system is currently operating at or near capacity and incremental capacity would reportedly be expensive to add. The supply option selected will depend on the magnitude of the volumes to be imported, the availability and assurance of pipeline capacity, and the cost of transporting the foreign crude oil into Ontario.

7.9   SUMMARY AND CONCLUSIONS

Canada's total crude oil **resource base** is very large and diverse, ranging from well defined and readily accessible resources of conventional oil and bitumen from the WCSB to largely undefined and less accessible resources in the frontier areas. However, bitumen and frontier resources, which account for the bulk of the total, are relatively expensive to produce, whereas the less expensive conventional resources in the WCSB are becoming less abundant reflecting the mature stage of exploitation of the basin.

Despite weakening oil prices, Canadian oil supply has increased moderately over the past few years, defying earlier projections by the NEB and the industry. This was due, mainly, to industry rationalization efforts, rapid technological progress and increased availability of investment capital. Among new technologies, horizontal drilling has had a particularly strong impact on oil supply through lower supply costs and accelerated production.

Technological change and oil price are the two key factors that will continue to have a significant impact on future crude oil supply. Since both factors equally affect producer netbacks – one through lower supply costs and the other through higher gross revenue – rapid technological progress may have the same net effect on supply as substantial oil price increases. This is clearly illustrated by comparing Canadian oil supply profiles for the Current Tech case (with high oil prices) and the High Tech case (with moderate prices).

Since Canada is a high-cost producer by world standards, and since real oil prices are generally expected to remain flat over the projection period, the prospects for future Canadian oil supply are critically dependent on continued technology-driven cost reductions. Although Canadian oil producers have no influence on world oil prices, they do have some degree of control over their production costs and operational efficiencies. This has recently been manifested through an impressive array of technological innovations described in this report. Since these innovations are not confined to Canada and are often applied worldwide, technological progress and oil prices are, at least to some extent, interrelated. This relationship requires further study. In this report, the High and Low Price sensitivities for the Current Tech case attempt to capture the widest possible range of uncertainty over Canadian oil supply.

TABLE 7-9

Exports and Imports of Crude Oil and Petroleum Products

(thousands of cubic metres per day)

Current Technology Case	1993	1994	1995	2000	2005	2010
Light Crude Oil						
Exports	77	85	90	72	69	64
Imports	85	82	84	89	97	121
Net Exports (Imports)	-9	3	6	-17	-28	-56
Heavy Crude Oil						
Exports	67	78	93	113	86	71
Imports	7	7	7	7	7	7
Net Exports (Imports)	60	71	86	106	79	64
Total Crude Oil						
Exports	144	163	183	185	155	136
Imports	92	89	91	96	104	128
Net Exports (Imports)	51	74	92	88	51	8
Products						
Exports	39	38	35	34	33	33
Imports	22	22	25	27	40	55
Net Exports (Imports)	17	16	10	8	-7	-22
Total Crude Oil and Products						
Exports	183	201	218	219	188	168
Imports	115	111	116	123	144	183
Net Exports (Imports)	68	90	102	96	44	-14

High Technology Case	1993	1994	1995	2000	2005	2010
Light Crude Oil						
Exports	77	87	94	83	88	73
Imports	85	81	83	87	93	97
Net Exports (Imports)	-9	5	11	-5	-5	-24
Heavy Crude Oil						
Exports	67	78	95	137	126	119
Imports	7	7	7	7	7	7
Net Exports (Imports)	60	71	88	130	119	112
Total Crude Oil						
Exports	144	165	189	220	213	192
Imports	92	88	90	94	100	104
Net Exports (Imports)	52	77	99	125	114	89
Products						
Exports	39	38	35	34	33	33
Imports	22	22	25	26	31	41
Net Exports (Imports)	17	16	10	8	2	-8
Total Crude Oil and Products						
Exports	183	203	224	254	246	225
Imports	114	110	115	121	131	144
Net Exports (Imports)	68	93	109	133	116	81

Note: The numbers in this table have been rounded.

Sources: Tables 7-6, 7-7 and 7-8.

TABLE 7-10

Light Crude Oil Requirements and Domestic Supply for Ontario
(thousands of cubic metres per day)

Current Technology Case	1994	1995	2000	2005	2010
Total Ontario Feedstock Requirements	**76.4**	**80.5**	**93.5**	**94.6**	**96.5**
Less: Domestic Supply other than Light Crude					
Heavy Crude	-13.1	-13.4	-14.2	-15.2	-15.8
Other Material	-5.3	-5.3	-5.3	-5.3	-5.3
Ontario Requirements for Light Crude	**58.0**	**61.8**	**74.0**	**74.1**	**75.4**
Total Available Domestic Light Crude Supply[1]	211.4	218.7	194.2	175.6	149.2
Less: Supply for Québec	-1.6	0.0	0.0	0.0	0.0
Supply for Prairies	-54.6	-58.1	-59.2	-58.5	-58.2
Supply for B.C.	-15.2	-9.7	-9.6	-9.5	-9.5
Minimum Exports	-30.0	-30.0	-30.0	-30.0	-30.0
Domestic Light Crude Supply Available for Ontario	**110.0**	**120.9**	**95.5**	**77.6**	**51.5**
Surplus(+) or Shortfall (-)	52.0	59.1	21.5	3.5	-23.9

High Technology Case	1994	1995	2000	2005	2010
Total Ontario Feedstock Requirements	**75.5**	**78.7**	**87.9**	**94.5**	**96.8**
Less: Domestic Supply other than Light Crude					
Heavy Crude	-13.1	-13.4	-14.2	-15.2	-15.8
Other Material	-5.3	-5.3	-5.3	-5.3	-5.3
Ontario Requirements for Light Crude	**57.1**	**60.0**	**68.4**	**74.0**	**75.7**
Total Available Domestic Light Crude Supply[1]	212.1	220.6	195.4	184.0	171.8
Less: Supply for Québec	-1.6	0.0	0.0	0.0	0.0
Supply for Prairies	-54.6	-58.0	-58.9	-58.6	-58.3
Supply for B.C.	-15.1	-9.7	-9.6	-9.5	-9.6
Minimum Exports	-30.0	-30.0	-30.0	-30.0	-30.0
Domestic Light Crude Supply Available for Ontario	**110.8**	**122.8**	**96.9**	**85.9**	**74.0**
Surplus(+) or Shortfall (-)	**53.7**	**62.9**	**28.5**	**11.9**	**-1.7**

1   Includes supply from Western Canada.

Sources: Appendix Tables A7-15 and A7-16.

Our crude oil **supply projections** can be summarized as follows. The mature stage of resource exploitation in the WCSB suggests that the supply of Western Canada's conventional oil, especially for light oil, is unlikely to be sustained over the long-term even in our High Tech case. However, horizontal drilling and other new technologies may allow production at current or higher levels for several years. Conventional oil supply in the WCSB declines gradually in the Current Tech case, from the peak levels reached in 1995 for light oil and in 1997 for heavy oil. In the High Tech case, peak levels are slightly higher but subsequent rates of decline are similar or even steeper for light crude oil.

Assuming continued technological progress and moderate to high oil prices, this decline in conventional oil production in the WCSB will be offset by increased supply from oilsands and frontier sources. Light oil supply from the East Coast offshore increases substantially in the Current Tech case with the development of both Hibernia and Terra Nova. As a result, East Coast offshore supply reaches 12 percent of total Canadian oil supply by the end of the projection period. In the High Tech case, offshore production increases even more (as some of the smaller fields are also developed), again reaching around 12 percent of higher Canadian overall production by the end of the projection.

Bitumen and synthetic oil supplies increase through the year 2000 in both technology cases. Increases in the High Tech case are higher and continue after year 2000. Higher differentials resulting from the penetration of new markets encourage upgrading and higher synthetic oil supply. In the Current Tech case, by contrast, increases in bitumen supply plateau due to higher natural gas prices.

As a result, total Canadian crude oil supply is expected in both cases to increase over the next few years and remain above the present level through the year 2010. Production gains are, of course, much larger in the High Tech case than in the Current Tech case.

The US$30 price sensitivity analysis for the Current Tech case indicates a supply profile that is even more favourable than the profile in the High Tech case. The supply prospects are drastically different in the US$15 price sensitivity. Total supply declines rapidly under this latter scenario as new projects are generally not economically viable. By contrast, all sources become viable at US$26, which suggests that the magnitude and the composition of Canadian crude oil supply are quite sensitive to price changes within the US$15-26 range.

Implications for Canada's net crude oil exports are as follows. In the Current Tech case, total crude oil supply does not fall below the present level until 2008, as the decline in conventional oil is offset by gains in bitumen, synthetic and frontier oil. This implies that Canada retains its net crude oil exporter status through the entire forecast. In the High Tech case and the High Price sensitivity, increases in total crude oil supply strengthen Canada's exporter status.

There are also important implications for Canada's pipeline capacity. As a result of the projected temporary rise in supply from western Canada in the Current Tech case, it is likely that currently approved pipeline capacity will be fully utilized during the period 1996 to 1999. This could result in some shut-in production if no remedial actions, such as the use of anti dragging agents or increases in pumping capacity, are taken. The rise in supply will also tend to delay the anticipated reversal of the Sarnia-to-Montreal pipeline to at least past the year 2000. The exact timing of this reversal is difficult to predict as it will not only depend on supply of light crude oil and equivalent from western Canada but also on other factors such as the relative costs of imported crude oil. In the High Tech case and the High Price sensitivity, substantial expansion of currently approved pipeline capacity would be required to accommodate the increasing supplies from western Canada. The need for a reversal of the Sarnia-to-Montreal pipeline would be further delayed in the High Tech Case or eliminated in the High Price sensitivity case.

Chapter 8

NATURAL GAS LIQUIDS

In this chapter, we examine the contribution of natural gas liquids (NGL) to the supply and demand for energy in Canada. The products included under the term NGL consist of ethane, propane, butanes (isobutane and normal butane) and pentanes plus. The chapter begins with an overview of the Canadian NGL production and transportation infrastructure. This is followed by a section on general supply considerations and a discussion of supply, demand and a supply – demand balance for each of ethane, propane and butanes. For pentanes plus we only discuss supply as the demand for pentanes plus has already been discussed in the immediately preceding crude oil chapter.

8.1 OVERVIEW OF THE CANADIAN NGL PRODUCTION AND TRANSPORTATION INFRASTRUCTURE

8.1.1 Extraction and Processing Facilities

When natural gas (mainly methane) is produced, it often contains significant amounts of heavier hydrocarbons (ethane, propane, butanes and pentanes plus), as well as water vapour, hydrogen sulphide, carbon dioxide and nitrogen. In order to meet the quality specifications required for pipeline transportation and to extract valuable by-products, the raw gas must be processed. Field processing usually involves removing the water vapour, some heavier hydrocarbons and contaminants such as acidic gases. The extraction of a portion of the heavier hydrocarbons (pentanes plus) may be necessary to prevent transportation problems associated with condensation of liquids in natural gas pipelines. There may also be an economic incentive, beyond meeting pipeline specifications, for even further extraction of liquids (ethane plus) from natural gas. This additional extraction can take place at either a field facility or at a straddle plant, sometimes referred to as a reprocessing plant. Field plants account for approximately 36 percent of ethane, 65 per cent of propane, 74 per cent of butanes and 94 percent of pentanes plus produced from natural gas.

There are approximately 630 field gas plants operating in western Canada. The design, size and complexity of these plants depend on the composition and volume of gas being processed. Simpler plants may provide only dehydration and possibly compression of

the gas whereas larger more complex plants may also remove hydrogen sulphide and carbon dioxide, extract NGL and sometimes fractionate the extracted NGL mix into specification products (ethane, propane and butanes).

Straddle plants have been constructed based on the economic benefits generated by further processing of pipeline quality gas. After the gas has been processed in the field, it still contains most of its ethane and some of the heavier liquids so that its heating value is normally well above the minimum required by gas purchasers. To extract this ethane as well as additional liquids, there are four large and two smaller straddle plants in Alberta. The large plants, one at Cochrane and three at Empress, reprocess most of the gas in the NOVA and Foothills pipeline systems that flows to markets outside Alberta. Most of the ethane produced in Alberta is extracted at these plants. In addition to ethane, these plants also produce either an NGL mix or specification propane, butanes and pentanes plus. The two smaller plants, both located near Edmonton, reprocess gas that is subsequently distributed locally.

Approximately 44 percent of NGL is produced as a mix and most of the mix is transported by pipeline to a fractionation facility where it is then split into its components for sale as specification products. Fractionation facilities in Canada are located at Fort Saskatchewan, near Edmonton and at Sarnia, Ontario.

Approximately 96 percent of the Canadian gas plant NGL supply comes from Alberta with lesser amounts originating in British Columbia (three percent), Saskatchewan (one percent) and a very minor amount in Manitoba.

Although natural gas processing plants and straddle plants are the primary sources of natural gas liquids, propane and butanes (approximately 15 per cent of supply) are also produced from the refining of crude oil, which contains a small amount of propane and butanes. Additional propane and butanes are generated as a by-product of refining processes.

8.1.2 Intraprovincial, Interprovincial and Export Delivery Systems

NGL produced in western Canada are moved by pipeline to both eastern Canadian and export markets through the IPL and Cochin pipeline systems,

originating in Edmonton and Fort Saskatchewan, Alberta respectively (Figure 8-1). The Cochin pipeline system transports high vapour pressure specification NGL products, ethylene and NGL mix. The IPL pipeline is not only a crude oil pipeline, but also carries oil products and propane plus mixes. The IPL system receives propane plus mixes in batches at Edmonton and also receives additional mix at Hardisty, Kerrobert and Cromer. These mixes are delivered to storage facilities in the Sarnia, Ontario area where they are subsequently fractionated. Deliveries beyond Sarnia are made by pipeline, road and rail transport. Smaller pipeline systems in addition to rail and road transport serve regional NGL domestic and export markets.

In southern Saskatchewan and Manitoba, the Petroleum Transmission Company pipeline transports specification propane and butanes from a straddle plant at Empress to various locations as far east as Winnipeg. In addition, propane-plus mixes are carried on the Westspur pipeline from Steelman to Cromer and on the Dome Kerrobert pipeline from Empress to storage and shipping facilities at Kerrobert (Figure 8-1).

Storage plays an important role in meeting peak NGL demand from a relatively constant supply. The demand for propane and butanes has large seasonal variations with the highest demand in the winter months. In order to provide economical, large capacity, high vapour pressure storage, a number of underground storage sites have been developed along NGL pipelines in areas of Alberta and Saskatchewan. These storage facilities are caverns that have been solution mined from thick beds of salt which are found in certain areas of Alberta and Saskatchewan. Similar storage caverns have been constructed in the Sarnia and Windsor areas of Ontario to receive and store NGL delivered by pipeline (Figure 8-1).

In Alberta and Saskatchewan, a network of pipelines which also transport crude oil allows the

FIGURE 8-1
NGL Interprovincial and Export Delivery Systems

movement of most NGL products from the gas plants to fractionation facilities or to storage facilities (Figure 8-2). These pipelines most often transport an NGL mix, although they can also move specification propane and butanes.

Specification ethane is collected by the Alberta Ethane Gathering System from straddle plants and field plants which produce ethane and is delivered to the Alberta users and to underground storage for later disposition (Figure 8-3). The primary market for ethane in Alberta is feedstock for ethylene plants located at Joffre, near Red Deer and at Fort Saskatchewan. To accommodate variations in supply and demand, ethane can be moved to large underground storage caverns near Edmonton, from where it can be used locally or shipped by pipeline to markets in the U.S. or to the region around Sarnia, Ontario.

Canada's main NGL export market is the U.S. Great Lakes area (Figure 8-1). Both the Cochin and IPL pipeline routes pass through this part of the United States en route to Ontario. Canadian NGL is able to compete with both offshore and U.S. domestic products in this market area and beyond by using connecting U.S. pipelines such as the MAPCO system. Further, NGL mixes are transported to the Sarnia area for fractionation and sale in nearby Canadian and Eastern U.S. markets.

8.2   NGL SUPPLY – GENERAL

This section describes the basis for our projections of NGL supply, first from natural gas production and

FIGURE 8-2
NGL Gathering Systems
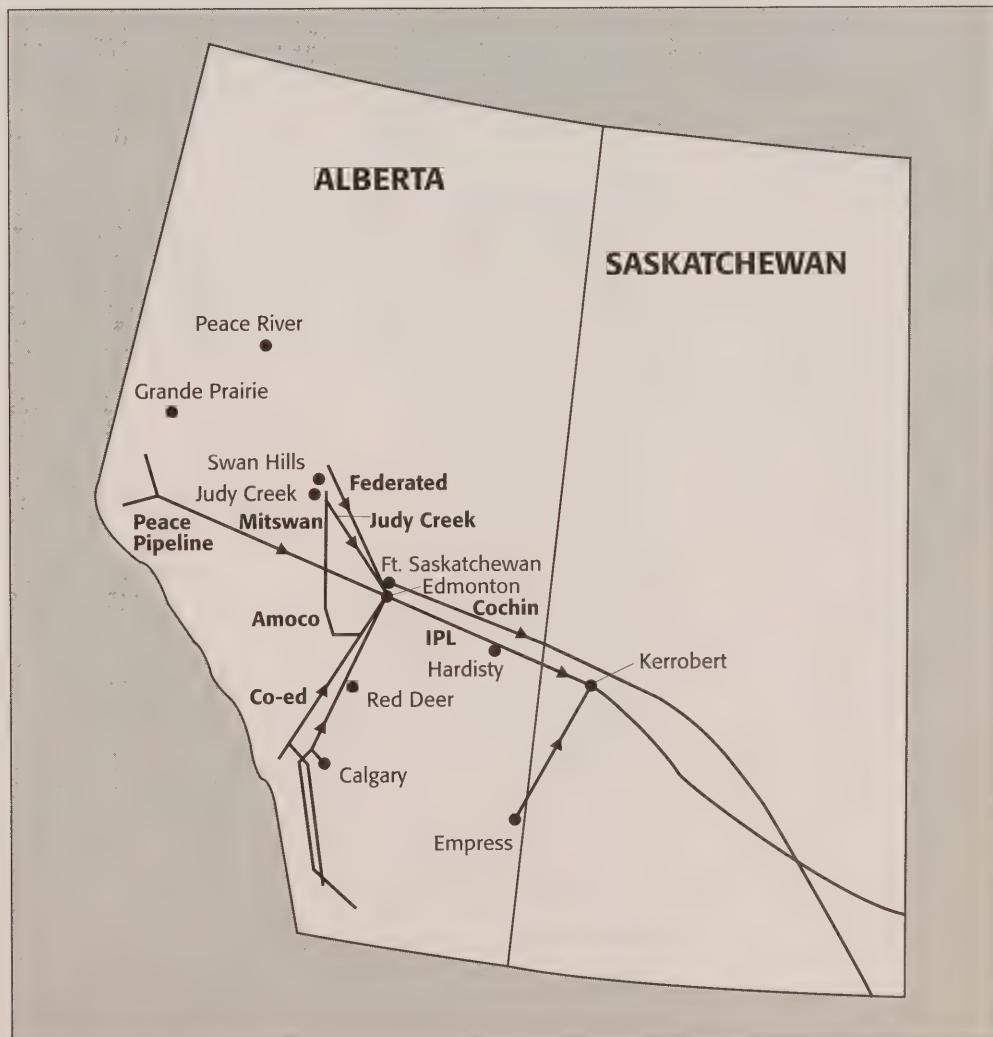
then from crude oil refineries. The projections of NGL supply are based on the corresponding projections of natural gas production. The assumptions relating to the supply of gas within the Current and High Tech cases as discussed in Chapter 6 therefore also apply to the supply of NGL from gas production.

NGL production from frontier gas fields has been investigated only from future gas production from the Sable Island area, offshore Nova Scotia, late in the projection period of the Current Tech case (Appendix Tables A8-4 to A8-6). NGL supplies from the Mackenzie Delta and from other frontier gas fields have not been considered since their projected development falls beyond the time frame of this report. Solution gas and gas caps of frontier oil fields can also potentially supply large volumes of NGL. In this report, projected pentanes plus production from Hibernia is included with the crude oil projections in Chapter 7.

The NGL supply projections from the most significant existing individual field gas plants were based on projections of gas production from the pools connected to each plant. The gas production projections were based on the Board's estimates of remaining hydrocarbon reserves for each pool. The liquids content of the gas as well as the pool performance and the capacities and performance of each plant were also considered. The NGL production from the remaining plants was estimated using projected gas flows and current yields. The expected NGL field plant production from unconnected and undiscovered reserves was also

FIGURE 8-3
Alberta Ethane Gathering System
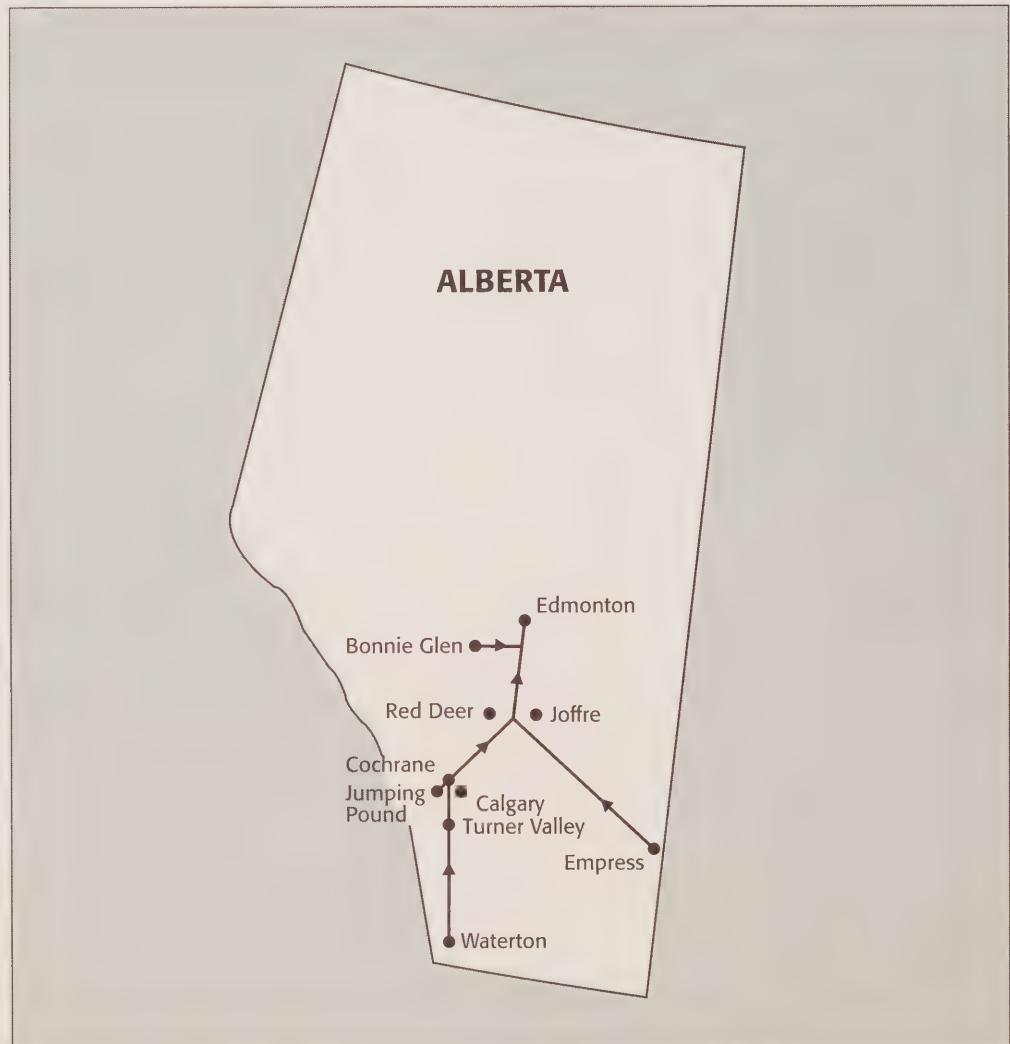
estimated from projections of gas production and the expected future product yields from field plants.

A separate projection of NGL production from the Empress and Cochrane mainline straddle plants was prepared using data on the respective pipeline flows based on NARG model results. The expected NGL component yields were based on current plants and used with projected pipeline flows. We assume that straddle plants will be either constructed or expanded to be able to process any additional gas. Some of these expansions and plans for new plants are already underway. This simplifying assumption may tend to give higher NGL volumes.

Table 8-1 shows estimates of NGL reserves for Alberta and British Columbia. The NEB has not developed its own NGL reserves estimates. These estimates prepared by the Alberta ERCB and the B.C. Ministry of Energy, Mines and Petroleum Resources for their respective provinces are used for reference only. The NGL projections in this report are based on NEB gas reserves estimates and NEB gas production projections.

The projection of NGL supply from gas plants is influenced mainly by the projected gas production and NGL yields. The yield is the volume of liquid product that is recovered from a volume of gas and is usually expressed as cubic metres of liquid per million cubic metres of gas.

NGL yields have shown substantial variation during the last 20 years with the yields for propane, butanes and pentanes plus decreasing since the mid 1970s as shown in Figure 8-4. Large volume ethane extraction did not start until the late 1970s and the ethane yields have only recently stabilized. Many of the cycling schemes which use liquids-rich gas have been responsible for high NGL yields in the past but these projects have terminated or are soon to terminate. In addition, the production rate of conventional light crude oil, which also provides a supply of NGL rich solution gas, is expected to continue to decline.

Under the Current Tech case, British Columbia is projected to produce an increasing share of gas towards the end of the projection period. Because of the lower overall NGL yields in British Columbia, there is a lowering effect on the NGL projections; however, the difference between the two cases is not significant. It is generally expected that future NGL production from the conventional gas supply areas will see some reduction in yields.

Propane and butanes are also produced by crude oil refineries as part of the refining process. The crude oil feedstock usually contains a small percentage of propane and butanes which can be recovered by distillation. In addition, propane and butanes are produced as by-products of other refining processes. As projections of refinery produced propane and butanes are based on projections of crude oil runs, there is only a modest increase in production rates over the forecast period. Table 8-2 and Appendix Table A8-2 contain projections of NGL production including refinery produced propane and butanes. Regional supply projections of refinery produced propane and butanes are shown in Appendix Tables A8-7 and A8-8.

TABLE 8-1

Natural Gas Liquids Reserves – Provincial Estimates
(Millions of Cubic Metres)

	British Columbia[1]	Alberta[2]
Ethane	-	312.0
Propane[3]		121.2
Butanes[3]		70.6
LPG[3]	10.7	191.8
Pentanes Plus	5.5	120.0

Notes:
1   Source: Hydrocarbon and By-Product Reserves in British Columbia, 1992, B.C. Ministry of Energy Mines and Petroleum Resources.
2   Includes volumes recoverable from field gas plants, reprocessing plants and solvent floods. Source: ERCB ST93-18. Alberta's reserves of crude oil, oil sands, gas, natural gas liquids, and suphur.
3   Propane and butanes in British Columbia are included in LPG.

8.3 NGL PRODUCT SUPPLY, DEMAND AND BALANCES

This section provides an overview of the supply and domestic demand for each of ethane, propane and butanes. The surplus available after allowing for domestic demand is potentially available for export. The United States is the main export market for Canadian ethane, propane and butanes.

NGL demand discussed in this section is a review of end use demand which has been discused in Chapter 4 as well as miscible flood demand which only appears in this chapter.

FIGURE 8-4

NGL Yields – Current Technology Case

cubic metres of liquid per million cubic metres of natural gas

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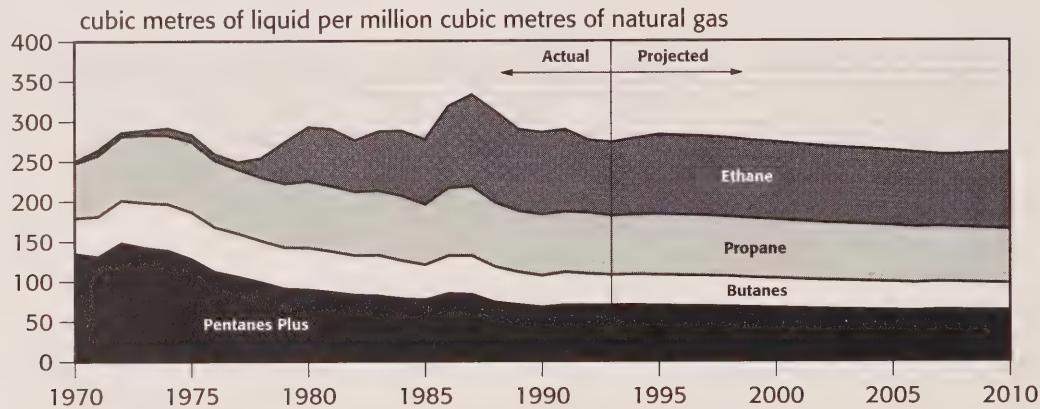
TABLE 8-2

Supply of Natural Gas Liquids

(Thousands of Cubic Metres per Day)

	1992	2000 Current Tech Case	2000 High Tech Case	2010 Current Tech Case	2010 High Tech Case
Gas Plants					
Ethane	28.3	41.2	34.8	39.4	43.9
Propane	23.9	31.3	26.7	27.8	32.9
Butanes	12.2	15.6	13.4	13.9	16.2
Pentanes Plus	21.9	28.4	24.3	25.9	29.4
Refineries					
Ethane	-	-	-	-	-
Propane	3.5	4.0	3.9	4.2	4.2
Butanes	2.7	3.2	3.1	3.3	3.3
Pentanes Plus	-	-	-	-	-
Total					
Ethane	28.3	41.2	34.8	39.4	43.9
Propane	27.4	35.3	30.6	32.0	37.1
Butanes	14.9	18.8	16.5	17.2	19.5
Pentanes Plus	21.9	28.4	24.3	25.9	29.4

Source: Appendix Table A8-2.

8.3.1 Ethane

The supply of ethane under the Current Tech case is projected to increase from the current level of 28.3 thousand cubic metres per day to a peak of 43.6 thousand cubic metres per day by 2006 and then decline to 39.4 thousand cubic metres per day by 2010. Under the High Tech case, ethane supply is projected to increase steadily to 43.9 thousand cubic metres per day by 2010 (Table 8-2 and Appendix Table A8-2). Details of our ethane supply projections are shown in Appendix Table A8-3.

Seventy percent of ethane demand consists of the feedstock requirements for the production of ethylene. Most of this demand originates in Alberta, specifically at a large ethylene complex near Joffre, which has been in operation since 1978, and a new, smaller plant at Fort Saskatchewan. About nine percent of petrochemical demand is from plants in Ontario. Through expansion and debottlenecking of existing ethylene plants, petrochemical demand for ethane is projected to increase from a current 15.3 thousand cubic metres per day to 34.8 thousand cubic metres per day by 2010 for the Current Tech case, and to 36.3 thousand cubic metres per day by 2010 for the High Tech case.

Approximately 30 percent of ethane demand is for miscible floods. Ethane is a major component (currently 69 percent) of the injected solvent (NGL mix) in miscible floods for enhanced recovery of crude oil. Currently, approximately 42 percent of NGL mix is injected into oil reservoirs. It is expected that much of the ethane injected in miscible floods will be eventually recovered. Based on current and future floods, this demand is expected to decline from a current level of 8.6 thousand cubic metres per day to approximately 2.9 thousand cubic metres per day by 2010 for the Current Tech case and decline to 3.8 thousand cubic metres per day for the High Tech case. Projections of ethane requirements for future miscible floods are net requirements which are adjusted for future flood production, and are based on expected future floods discussed in Chapter 7. These projections are even less accurate than our projections of miscible floods as we have to cope with two more levels of uncertainty. First, there are uncertainties associated with the cost and availability of specific solvent components like ethane, propane and butanes which are to some extent interchangeable. Secondly, some projects could use carbon dioxide as a solvent rather than hydrocarbons. For our projections, we assumed that carbon dioxide will gradually supply up to fifty percent of the total solvent requirements by the year 2010.

The supply/demand balances for ethane for each of the Current and High Tech cases are displayed in Figures 8-5 and 8-6 and can be found in tabular form in Appendix Table A8-9. In each case the supply of ethane is projected to exceed demand throughout the projection period and provide for potential exports. Although no allowance was made for potential ethane extraction from Northeast British Columbia as there are currently no transportation facilities in place, the area has potential to increase the projected ethane supply. Gas from the offshore Nova Scotia Sable Island area also contains large quantities of ethane which could be extracted if a market were available.

8.3.2 Propane

Propane supply from both gas plants and refineries under the Current Tech case is projected to increase from the current level of 27.4 thousand cubic metres per day to 37.2 thousand cubic metres per day by 2006 and then decline to a level of 32.0 thousand cubic metres per day by 2010. Projections of propane supply under the High Tech case result in an increase to a level of 37.1 thousand cubic metres per day by 2010 (Table 8-2 and Appendix Table A8-2). Details of our projections of propane supply from gas plants are shown in Appendix Table A8-4 and regional projections of propane supply from refineries are shown in Appendix Table A8-7.

With regard to demand, propane is the most versatile component of NGL. Its uses include residential and commercial space heating, agricultural crop drying, industrial heat and engine fuels, transportation fuels and as miscible flood solvent. During the last two decades, increasing volumes of propane have also been used as petrochemical feedstock. Propane is used as a feedstock in olefins production to make ethylene and propylene, which in turn are feedstock for many derivative products.

Propane demand, more fully explained in the demand Chapter 4, is expected to continue to increase in all end use sectors, particularly in the petrochemical and transportation sectors where demand is projected to increase by 49 percent and 31 percent, respectively, by 2010. Propane end use demand is projected to increase from the current 12.1 thousand cubic metres per day to 16.3 thousand cubic metres per day for the Current Tech case and to 16.8 thousand cubic metres per day the High Tech case. In addition, propane requirements for miscible flooding are projected to increase from the current 2.1 thousand cubic metres per day to 6.9 thousand cubic metres per day by 2010 for the Current Tech case, and to 9.1 thousand cubic metres per day for the High Tech case. Uncertainties with regard to the use

of ethane in future miscible floods, as noted in the ethane section, also apply to propane.

Figures 8-7 and 8-8 and Appendix Table 8-10 show the relationship between propane supply and demand for the Current and High Tech cases. Both cases provide for a level of supply in excess of demand to potentially continue exports at recent historical levels.

8.3.3 Butanes

The supply of butanes from gas plants and refineries under the Current Tech case is projected to increase from the current level of 14.9 thousand cubic metres per day to 19.7 thousand cubic metres per day by 2006 and then decline to 17.2 thousand cubic metres per day by 2010. Butane supply under the High Tech case continues to increase to a level of 19.5 thousand cubic metres per day in 2010 (Table 8-2 and Appendix Table A8-2). Details of our projections for butanes supply from gas plants are shown in Appendix Table A8-5 and regional projections of butanes supply from refineries are provided in Appendix Table A8-8.

Butanes are used as feedstock for both refinery and petrochemical processes. The main petrochemical use for butanes is a feedstock in the production of methyl tertiary butyl ether (MTBE), a gasoline blending component, with lesser amounts used as feedstock to produce olefins and acetic acid. Most of the MTBE production is expected to be sold in the export market.

FIGURE 8-5

Ethane Supply and Demand – Current Technology Case

Source: Appendix Tables A8-1 and A8-9
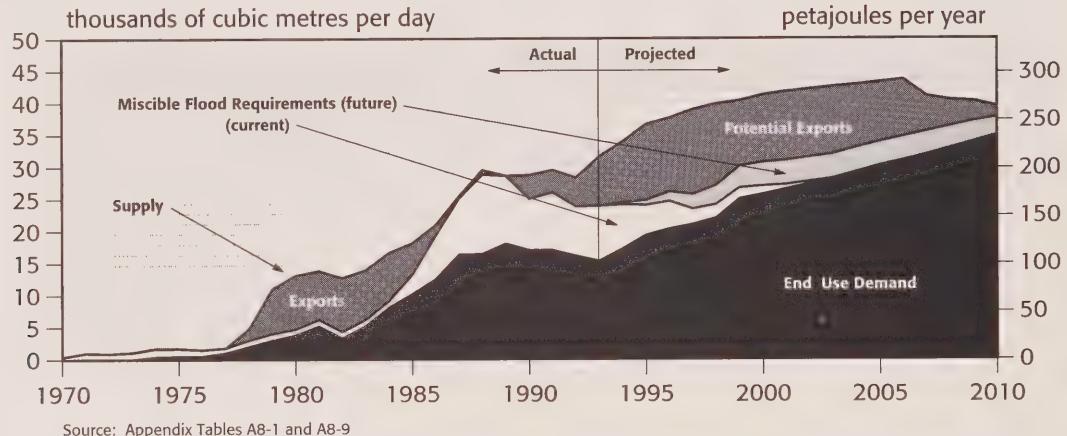
FIGURE 8-6

Ethane Supply and Demand – High Technology Case

Source: Appendix Tables A8-1 and A8-9
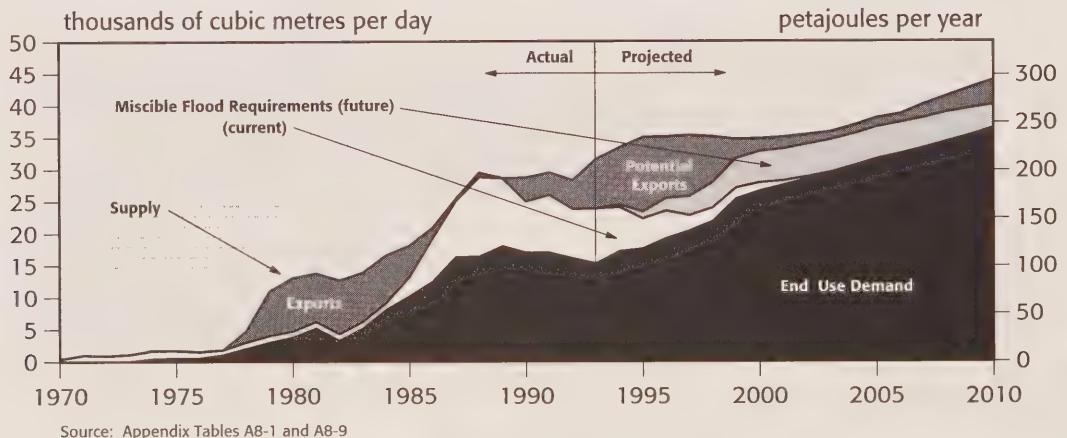
A small amount of butanes is injected into miscible floods as part of an NGL mix.

Refineries are currently the largest user of butanes representing 52 percent of butanes demand. In refineries, butanes are blended into gasoline and used in refinery processes. Refinery requirements are projected to increase from the current 4.9 thousand cubic metres per day to 6.1 thousand cubic metres per day by 2010 for both the Current and High Tech cases. This projection is based on expected refinery gasoline production and does not account for any further reductions in gasoline vapour pressure limits beyond those set in 1992.

The petrochemical requirements for butanes are forecast to increase from the current level of 3.5 thousand cubic metres per day to 7.3 thousand cubic metres per day for the Current Tech case and to 7.6 thousand cubic metres per day for the High Tech case.

Butanes are seldom a major component of miscible flood solvent but are often injected because they are already a component of a NGL mix. The current and future miscible flood requirements for butanes are projected to increase from a current level of 1.0 thousand cubic metres per day to 1.8 thousand cubic metres per day for the Current Tech case and to 2.3 thousand cubic metres for the High Tech cases. The projection of butanes requirements for future miscible floods has the same uncertainties noted for ethane.

The relationship between butanes supply and demand for the Current Tech case is presented in Figure

FIGURE 8-7

Propane Supply and Demand – Current Technology Case

Source: Appendix Tables A8-1 and A8-10
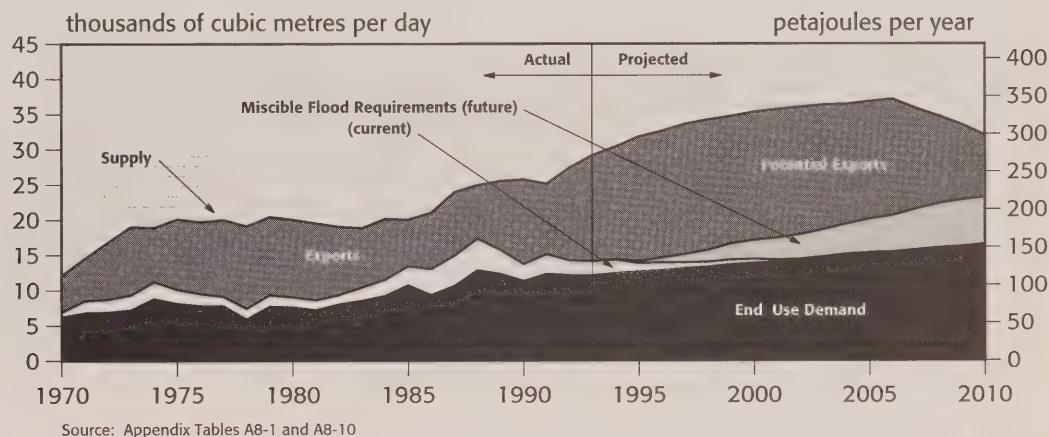
FIGURE 8-8

Propane Supply and Demand – High Technology Case

Source: Appendix Tables A8-1 and A8-10
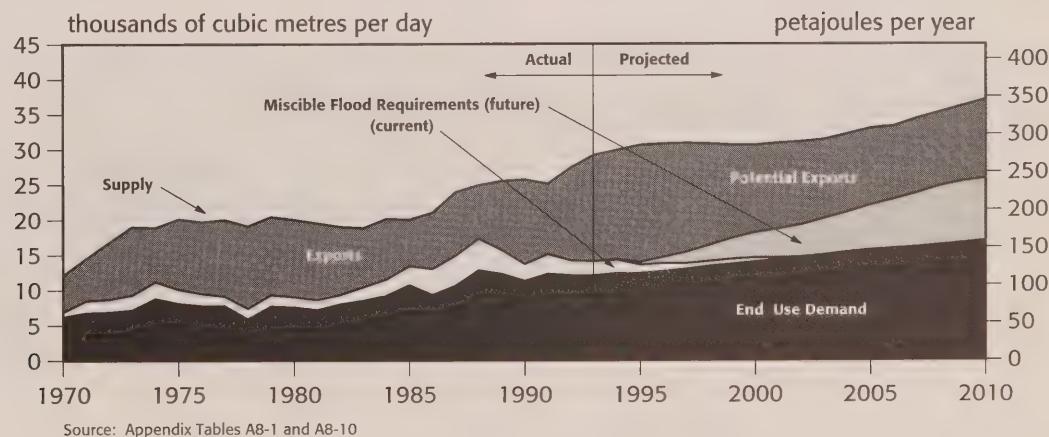
8-9. This case projects that there will be ample supply of butanes to support the current levels of exports until 2006. The High Tech case is presented in Figure 8-10 which shows a reducing butanes surplus until approximately 2000 and continuing at that level until 2010. Details of the supply and demand relationship are shown in Appendix Table A8-11.

8.3.4 Pentanes Plus

The supply of pentanes plus from natural gas production under the Current Tech case is projected to increase from the current level of 21.9 thousand cubic metres per day to 29.3 thousand cubic metres per day by 2005 and then decline to 25.9 thousand cubic metres per day by 2010. With the High Tech case, pentanes plus increase to 29.3 thousand cubic metres per day by 2010 (Table 8-2, Appendix Table A8-2). Details of the pentanes plus supply projections are shown in Appendix Table A8-6. Disposition of pentanes plus is included with crude oil in Chapter 7.

8.4 Concluding Comments

Canada has an extensive and well developed infrastructure for NGL production, transportation and distribution.

Domestic demand for NGL is expected to increase throughout the forecast period. Domestic demand for ethane is projected to increase as a result of debottlenecking and expansion of existing ethylene plants. Propane demand is projected to rise in all sectors

FIGURE 8-9

Butanes Supply and Demand – Current Technology Case

Source: Appendix Tables A8-1 and A8-11
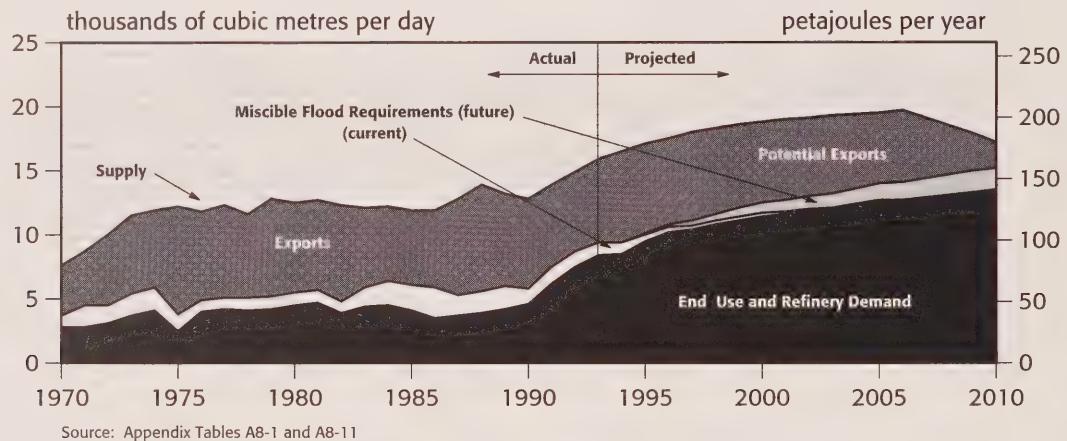
FIGURE 8-10

Butanes Supply and Demand – High Technology Case

Source: Appendix Tables A8-1 and A8-11
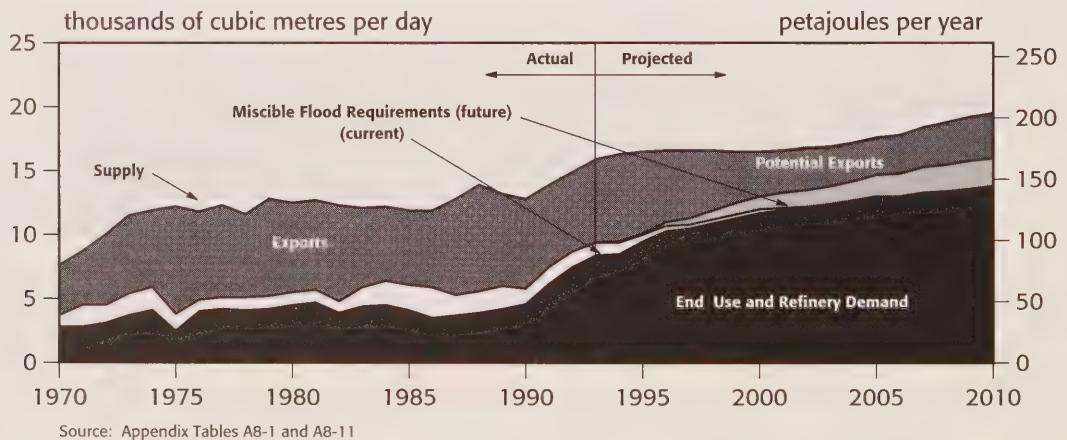
with the most significant increases being in the transportation and petrochemical sectors. The expansion of the existing MTBE plant and the construction of a new plant will provide an increasing demand for butanes.

Natural gas processing is the primary source of NGL supply but some propane and butanes are produced at crude oil refineries. The main determinants of future supply are natural gas production and liquids yields.

Liquids yields from natural gas are expected to marginally decline over the projection period. However, there are several uncertainties such as those related to the composition of future gas discoveries. NGL supply is expected to increase over the forecast period as natural gas production increases in response to rising export and domestic demand.

The projections of NGL supply in this report are not significantly different from those in the control case of the 1991 report. Projected NGL production in the Current Tech case is somewhat higher than the 1991 control case until the year 2006 and is lower than the control case by 2010. Projected NGL production in the High Tech case is slightly lower than the 1991 control case until the year 2005 whereafter it becomes higher. The future NGL supply will depend on the level of natural gas production and the volume of gas produced from B.C. compared to Alberta.

These supply projections are, in the later years, largely based on estimates of potential gas supply, and the incentive to extract liquids which is primarily dependent on relative oil/gas prices. In these projections, gas prices rise relative to oil over the projection period, which may have a negative impact on the economics of NGL extraction.

This analysis indicates that for ethane, propane and butanes, there will generally be excess supply over domestic demand during the projection period. Ethane supply exceeds domestic demand in both cases by significant amounts throughout the projection period. To the extent that export markets are not available for the surplus volumes, the ethane will be left in the gas stream and sold with the natural gas.

COAL

In this chapter, we examine the supply of and demand for Canadian coal in domestic and international markets. We begin with a review of various types of coal and the remaining resources and reserves of each type. This is followed by projections of domestic demand, exports, imports and production. The chapter concludes with comments on our coal supply and projections of demand.

9.1 QUALITY AND TYPES OF COAL

The quality of Canadian coal ranges from the lower quality lignite and subbituminous classes to the higher quality bituminous coals and anthracite (Appendix Table A9-1). As coal quality increases, so too does the energy content. An important characteristic of coal is sulphur content. Reduced acid gas emissions are essential to continued acceptability of coal. Increasing concern over sulphur dioxide emissions and acid rain place a premium value on western coal reserves which generally have less than one percent sulphur. Atlantic coals typically contain more sulphur. Coal use varies depending on the quality of the coal:

- Lignite and subbituminous coals, which because of their low energy content are not economic to transport over long distances, are used mainly for thermal power generation close to the mine mouth.

- Bituminous coals are also used for thermal power generation and their higher quality makes transportation of these coals to more distant markets a viable option. Some bituminous coals have properties which make them suitable for use in the production of coke, a reducing agent and heat source for the steel industry. These metallurgical coals require preparation to meet market specifications, which involves, among other things, reducing the mineral matter, sulphur and moisture content.

- Although Canadian deposits of anthracite are currently not exploited, they may be suitable for some thermal applications. Small amounts of imported anthracite are used for titanium smelting.

9.2 RESERVES AND RESOURCES

Coal resource estimates only include coal deposits which occur within specified limits of thickness and depth from the surface. These limits are intended to reflect both economic and technical feasibility of exploitation.

These estimates are commonly divided into two main categories: resources of "immediate interest" and resources of "future interest". To be of immediate interest, resources must consist of coal seams with a combination of thickness, quality, depth and location which render them attractive for further exploration or early development. Resources of future interest would be more costly to produce because of either their remoteness or depth of occurrence. Both categories are subdivided into "measured", "indicated" and "inferred" resources, according to the amount of exploration, sampling and analysis that has been conducted. There is a high level of certainty that measured resources exist and least assurance about inferred resources.

Almost 95 percent of resources of immediate interest are located in Western Canada (Table 9-1). Over 60 percent of resources of immediate interest consists of low quality lignite and subbituminous coal deposits located, for the most part, in Alberta. Higher quality bituminous resources of immediate interest are found mainly in British Columbia, but substantial deposits also occur in Alberta and Nova Scotia. Resources of future interest are concentrated in the Arctic and at greater depths in the Plains region of Alberta (Appendix Table A9-2).

The portions of the measured and indicated resources of immediate interest that are currently developed or considered suitable for commercial development are called reserves. Reserves are deposits that have been adequately delineated through exploration and sampling and which can be considered economic for mining using current technology.

The most recent available national assessment of reserves is as of 31 December 1985[1] (Table 9-2). The overall picture of a large inventory of reserves relative to production levels provided by the 1985 data has not changed over the subsequent period. Remaining recoverable reserves are some 100 times Canada's 1992 production of 65 megatonnes (Mt).

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1 In order to obtain a current estimate one would have to take into account production and any evaluations of mining properties which have been undertaken since 1985. More current estimates are available for some provinces and for some coal deposits, however, we have chosen to reference an older but complete and consistent set of data.

TABLE 9-1

Summary of Canada's Coal Resources of Immediate Interest by Province

(Megatonnes)

Province	low volatile bituminous-anthracite	medium-low volatile bituminous	high-medium volatile bituminous	subbituminous-high volatile bituminous	lignite-subbituminous	Total
British Columbia	1 610	9 270	7 190	645	1 090	19 805
Alberta	815	3 515	1 710	7 420	33 475	46 935
Saskatchewan	–	–	–	–	7 595	7 595
Ontario	–	–	–	–	180	180
New Brunswick	–	–	75	–	–	75
Nova Scotia	–	–	1 405	–	–	1 405
Yukon Territory and District of Mackenzie	90	–	150	350	2 290	2 880
Canada	2 515	12 785	10 530	8 415	44 630	78 875

Source: *Coal Resources of Canada, Paper 89-4*, Geological Survey of Canada, 1989

Note: Thermal coals generally include the lignite-subbituminous, subbituminous-high volatile bituminous and low volatile bituminous-anthracite classes. Metallurgical coals generally include the medium-low volatile bituminous and high-medium volatile bituminous classes.

TABLE 9-2

Remaining Recoverable Reserves of Coal by Province and Class at 31 December 1985

Province	Class	Megatonnes	Petajoules
British Columbia	Lignitic	566	7 600
	Bituminous		
	Thermal	433	10 836
	Metallurgical	1 563	39 114
Alberta[1]	Subbituminous	871	15 800
	Bituminous		
	Thermal	800	17 115
	Metallurgical	240	5 135
Saskatchewan	Lignitic	1 670	23 000
New Brunswick	Bituminous		
	Thermal	21	500
Nova Scotia	Bituminous		
	Thermal	300	7 663
	Metallurgical	115	2 937
Canada	Lignitic	2 236	30 600
	Subbituminous	871	15 800
	Bituminous		
	Thermal	1 553	36 114
	Metallurgical	1 918	47 186
	Total	6 578	129 700
Canada	Thermal[2]	4 660	82 514
	Metallurgical	1 918	47 186

Source: *Coal Mining in Canada: 1986, Report 87-3E*, CANMET, September 1987.

Notes:

1   The ERCB estimates coal reserves within mine permit boundaries to be 2599 megatonnes as of 31 December 1992. (ERCB ST93-31)

2   Thermal includes all lignitic, subbituminous and thermal bituminous reserves.

Reserves of lignite are mainly found in Saskatchewan, whereas all subbituminous reserves are located in Alberta. Most of Canada's metallurgical coal reserves are in British Columbia with smaller volumes located in Alberta and Nova Scotia. Over 50 percent of Canada's thermal coal reserves are in Alberta, with the remainder in British Columbia, Nova Scotia and New Brunswick. Figure 9-1 shows the location of current operating coal mines in Canada as well as rail routes and ports.

9.3 PRICES

Canadian coals compete in domestic and international energy markets with other fuels such as heavy fuel oil and natural gas for electricity generation, as well as with coals from other producing countries. Historically the price of coal has been below that of oil but generally followed crude oil trends. However, in recent years the price of coal has been driven down relative to the crude oil price due to excess availability of coal supply.

A worldwide oversupply of coal occurred in the 1980s as a result of a general slowdown in economic activity and the construction of several new mines dedicated to export markets, including some by new low cost competitors such as China and Colombia. This led to decreasing coal prices for Canadian exporters throughout most of the 1980s. Nominal prices for coal firmed up by the end of the 1980s as a result of a tightening of the supply situation caused by increased demand for coal by the steel industry and by electric utilities. However, prices for exports in the early 1990s were essentially constant (Table 9-3). As we foresee no important changes to production costs, export prices should not change much from current levels.

FIGURE 9-1
Principal Canadian Coal Mines

With respect to domestic markets, we assume that the price of coal for electricity generation and at the industrial burner tip will remain constant in real terms. This implies that the cost of any incremental capacity required to meet domestic demand at either existing mines or in the form of new mine developments will not increase from current levels.

Most Canadian mines are surface mines which generally have much lower production costs than do underground mines. Generally, costs for Canadian coals at the mine mouth are competitive with mine mouth costs at other operations throughout the world. However, the delivered cost consists of both production and transportation costs. The competitive cost of Canadian coal in the export market is discussed in the export section.

9.4   DOMESTIC COAL DEMAND

For the first half of this century, coal was the major source of energy in Canada, accounting for one half of primary energy demand by 1950. During the 1950s and 1960s oil and natural gas displaced coal used for space heating and in the industrial sector. In the 1960s, increased use of coal in Ontario by the steel industry and by electric utilities reversed the decline in demand. Expansion in coal demand since 1970 has been primarily for electricity generation in Alberta, Saskatchewan and Nova Scotia.

Figure 9-2 illustrates the trend in domestic coal demand over the past ten years. Thermal coal demand for power generation has increased at an average annual rate of 2.8 percent from 33.7 Mt in 1982 to 44.6 Mt in 1992. The majority of this growth has been in Alberta where coal consumption for power generation rose at an average annual rate of 6.1 percent from 13.2 Mt in 1982 to 23.7 Mt in 1992.

During the same time period, industrial coal demand has declined at an average annual rate of 1.8 percent from 7.8 Mt in 1982 to 6.5 Mt in 1992.

9.4.1   Thermal Coal Demand

In 1992, 46.1 Mt of thermal coal were consumed in Canada. Roughly 97 percent of this was for power generation. The remainder was consumed primarily by the cement industry and the smelting and refining industry.

The demand for thermal coal for the production of electric power in Canada is projected to increase at an average annual rate of 2.6 percent from 44.6 Mt in 1992 to 71.2 Mt by 2010 in the Current Tech case. In the High Tech case, natural gas is used to a much greater extent for electricity production. As a result, demand for coal

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TABLE 9-3

Export Contract Base Price of Coal Exports to Japan

Year	Metallurgical Luscar – Medium Volatile[1] (dollars per tonne)		Thermal Coal Valley/Obed Marsh[1,3] (dollars per tonne)	
	$U.S.	$C 1993[2]	$U.S.	$C 1993[2]
1970	11.86	47.11	n.a.	n.a.
1975	46.85	121.49	n.a.	n.a.
1980	52.79	105.61	n.a.	66.74[4]
1985	50.43	88.08	36.00	62.87
1990	52.80	64.88	36.10	44.36
1991	51.80	60.84	35.30	41.46
1992	51.30	62.88	34.46	42.24
1993	49.30	63.61	32.20	41.55

Source: *Coal Information 1993*, International Energy Agency, 1993.

Notes:
1   FOBT.
2   Calculated using the Canadian GDP deflator and Canada/U.S. exchange rates.
3   Coal Valley is shown through 1988 with a calorific value of 6350 kcal/kg GAD, Obed Marsh with a calorific value of 6050 kcal/kg GAD between 1989 and 1991, and 5858 kcal/kg GAR starting in 1992.
4   Price is in Canadian dollars for 1980, and was calculated using the Canadian GDP deflator.

in the High Tech case is projected to grow at an average annual rate of 1.8 percent, reaching 62.0 Mt in 2010 (Figure 9-2).

The three prairie provinces, Ontario, New Brunswick and Nova Scotia use coal to generate electricity. In Alberta it is assumed that, in the Current Tech case, conventional coal-fired generation will be favoured to replace unit retirements and to satisfy the base load component of future load growth. In the High Tech case approximately 1 700 MW of coal-fired generation is displaced by natural gas-fired combined cycle capacity.

Under the Board's projection of electrical load for Saskatchewan, an additional 272 MW coal-fired unit is projected to be installed at Shand in the Current Tech case. In the High Tech case a natural gas-fired combined cycle block provides the additional capacity.

In Manitoba, the Brandon and Selkirk coal-fired generating stations are scheduled for retirement during the projection period. Since no new coal-fired units are projected to be installed, coal demand for electricity generation in the province is expected to become zero.

In Ontario, coal-fired electricity generation declined in the early 1990s due in part to the introduction of an sulphur dioxide cap. However, the demand is projected to gradually increase to well above historic levels during the latter half of the projection period. The combined effects of the commissioning of four units at the Darlington nuclear station, and minimal load growth during in the early 1990s, prompted Ontario Hydro to mothball some 2 100 MW of coal-fired generation and to slate one unit at the Bruce nuclear station for retirement in 1995. It is assumed that the mothballed

coal-fired generation capacity will be brought back into service as required to satisfy future load growth. Additional generation will likely be provided by new hydroelectric development followed by coal-fired units in the Current Tech case, and by natural gas combined cycle generation in the High Tech case.

In New Brunswick, N.B. Power commissioned the first 443 MW coal-fired unit at Belledune in 1993. This unit will burn both imported and local bituminous coal. The expected increase in coal consumption in New Brunswick will be offset somewhat by the closure of the Grand Lake and Chatham coal-fired generating stations, and by the conversion of a part of the Dalhousie generating station from coal to orimulsion, a bitumen-water emulsion produced in Venezuela. We project that the next base load generating unit in New Brunswick will be an addition to the Belledune station in the middle of the next decade.

In 1993, Nova Scotia Power Inc. (NSPI) commissioned a 143 MW coal-fired unit at Point Aconi and mothballed two 20 MW coal-fired units at Trenton. We expect that NSPI will bring these units back into service beginning in 2000.

The cement industry and the smelting and refining industry are the largest industrial consumers of thermal coal representing 44 percent and 30 percent respectively of the industrial sector thermal coal demand. Thermal coal use in the industrial sector (excluding bitumen thermal recovery projects) is expected to increase at an average annual rate of 1.9 percent from 1.6 Mt 1992 to 2.2 Mt in 2010.

In Alberta, the use of coal, rather than natural gas, to generate steam for in situ recovery of bitumen could

FIGURE 9-2

Domestic Coal Demand – Current and High Technology Cases

Source: NRCan, *Statistical Review of Coal in Canada*, 1992 and Appendix Table A9-5
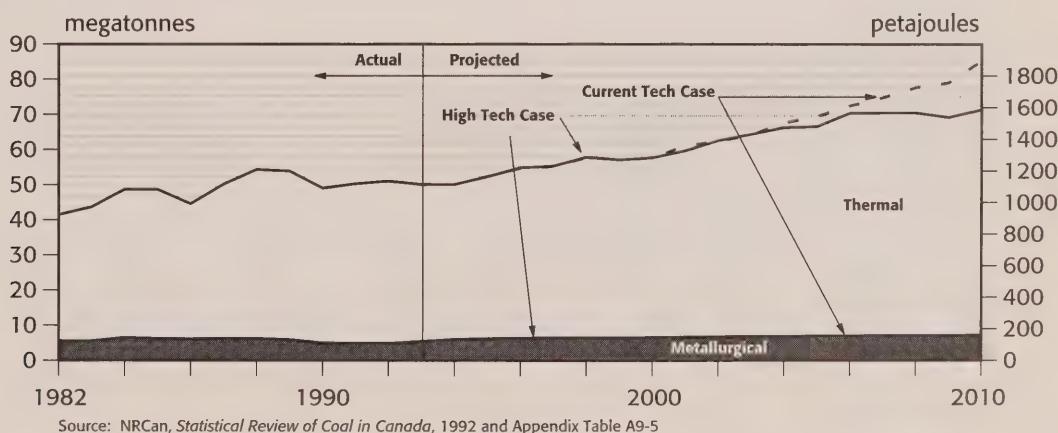
provide a new market for western coal. Current industry estimates suggest that coal is competitive with natural gas in some projects at a gas price of $3 per gigajoule. Based on our gas price projections in the Current Tech case which exceed this level in 2005, and based on projected rapid growth of bitumen production, demand for subbituminous coal for bitumen production is projected to grow from 0.5 Mt in 2006 to 4.7 Mt in 2010.

9.4.2 Metallurgical Coal Demand

Metallurgical coal demand in Canada is primarily for the production of steel in Ontario. In 1992, the Ontario steel industry consumed 4.9 Mt of metallurgical coal, all of which was imported from the U.S. We expect demand for metallurgical coal in Ontario to continue to be met by imports in the future. Projected metallurgical coal demand is shown in Figure 9-2.

In both the Current and High Tech cases growth in the Ontario iron and steel industry, which averages 2.6 percent annually over the projection period, reflects a healthy provincial auto industry. Increased use of pulverised coal injection (PCI), and electric arc furnaces (EAFs), are expected to result in a continued decline in the quantity of coal used per unit of steel produced (These technologies are described in more detail in the inset). As a result, steel industry coal demand is projected to increase at a slightly slower rate than GDP, averaging two percent annually from 1992 to 2010.

9.5 COAL EXPORTS

Canadian coal exports greatly increased during the 1970s and 1980s when bituminous coal resources were developed in Alberta and British Columbia to serve Asian markets for thermal coal and the Japanese metallurgical coal markets. Large export contracts with Japanese steel makers led to the opening of new mines and construction of a bulk shipping terminal at Roberts Bank near Vancouver in 1970. This allowed exports to increase 50 percent during the early 1980s. Figure 9-3 shows historical export volumes by province of origin.

From 1984 to 1991 exports rose at an average annual rate of 4.5 percent to reach a record 34.1 Mt in 1991. In 1992, due to a combination of labour and financial problems in the British Columbia coal industry, Canadian coal exports declined to 28.2 Mt, of which 82 percent were metallurgical and 18 percent thermal. These developments, as well as a decline in world demand for metallurgical coal, resulted in a decline in British Columbia exports from 24.3 Mt in 1991 to 16.7 Mt in 1992. Exports from the east coast fluctuated over the last ten years and currently account for less than five percent of total exports.

Pulverized Coal Injection and Minimills

Pulverized Coal Injection (PCI)

This technology involves injecting pulverized non-coking coal directly into the base of the blast furnace, reducing the amount of coking coal required. PCI technology results in large cost savings for the following three reasons. First, since PCI technology utilizes less expensive grades of coal, substituting pulverized coal for coking coal saves the user the coking coal premium. Second, there is a reduction in the total amount of coal required per unit of steel output, every tonne of pulverized coal injected replaces one and one-half tonnes of coking coal. Third, the use of PCI technology results in longer oven life, thus postponing the replacement of aging coke ovens. These savings have resulted in a trend toward increased world consumption of pulverized coal, from 4.4 Mt in 1987 to 14 Mt in 1991, which is expected to continue.[2]

Minimills

Minimills process scrap steel in electric arc furnaces (EAFs). They require fewer employees, need a much smaller initial investment than traditional coke fired plants, and produce less air and water pollution. Already, 28 per cent of the world's steel is made in EAFs, up from 14 per cent two decades ago. In North America the share of steel produced in EAFs is much higher at approximately 40 per cent. Many of the world's blast furnaces, including those in Japan, are nearing the end of their productive lives, thus the movement toward minimills is expected to continue worldwide.

Market penetration of EAFs is expected particularly in flat products such as beams and sections used for construction. Production of the highest quality rolled steel used in automobiles and appliances will require a technological breakthrough before EAFs can be used. Other constraints on growth in EAF production include the availability of clean scrap, and the need for secure supplies of low cost electricity.

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2   *Coal Information 1992*, International Energy Agency, OECD, 1993, p. 45.

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010

Most of Canada's coal exports continue to be metallurgical coal shipped from British Columbia and Alberta. The principal export destinations for both types of coal are Japan and South Korea. Japan received 57.3 percent and South Korea 16.4 percent of Canadian coal exports in 1992. Other destinations include Europe, Latin America and the United States (Figures 9-4 & 9-5 and Appendix Table A9-3).

Thermal coal exports in 1993 were estimated to decline by 19 percent to 4.3 Mt due to reductions in both Nova Scotia and British Columbia exports. In Nova Scotia, the explosion and closure of the Westray mine has resulted indirectly in a 0.5 Mt per year reduction in thermal exports to Europe. In British Columbia, the closure of the Balmer and Greenhills mines in the early part of the year resulted in a further loss of 0.6 Mt.

9.5.1 Metallurgical Coal Exports

Although exports declined initially in 1993 due to labour problems in some British Columbia mines, these problems have now been resolved and, based on the most recent monthly export levels, 1993 metallurgical coal exports should total approximately 23.9 Mt, an increase of 4.4 percent from 1992. The largest market for Canadian metallurgical coal remains the Asian market and mainly the Japanese and South Korean steel industries. There is also potential for growth in Canada's exports to Europe, particularly Germany, as discussed later.

However, the outlook for metallurgical coal demand in these markets as in other markets is moderated by the following factors:

- growth in world steel demand will be restrained due to the continued increase in the use of plastics and other substitutes in automobile manufacturing;

- increased use of pulverized coal injection will result in a steady decline in the amount of metallurgical coal required per unit of steel output;

- production through the use of electric arc furnaces, which do not require coking coal, is expected to increase substantially.

The Asian Market for Metallurgical Coal

Japanese demand for metallurgical coal is expected to decline steadily. Slow expected growth in steel production, combined with increased use of PCI technology (all thirty Japanese blast furnaces, which currently account for over two thirds of Japan's total steel production, are expected to be using PCI technology by the end of 1994), as well as an increase in the share of steel produced in EAFs will all contribute to this decline. The United States Energy Information Administration (EIA) projects Japanese imports of metallurgical coal to decline from 66.4 Mt in 1992 to 46 Mt by 2010, a decline of 31 per cent, while the Australian Bureau of Agriculture and Resource Economics (ABARE) predicts a decline of 14 per cent by 2005. As Canada is not currently a major producer of coals suitable for PCI technology, we are not currently in a position to benefit from the increased demand for pulverized coal. However, recently completed studies to predict the suitability of Canadian coal for PCI technology show the thermodynamic suitability of

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FIGURE 9-3
Total Historical Coal Exports by Province

Source: *Statistics Canada Cat. no. 45-002*
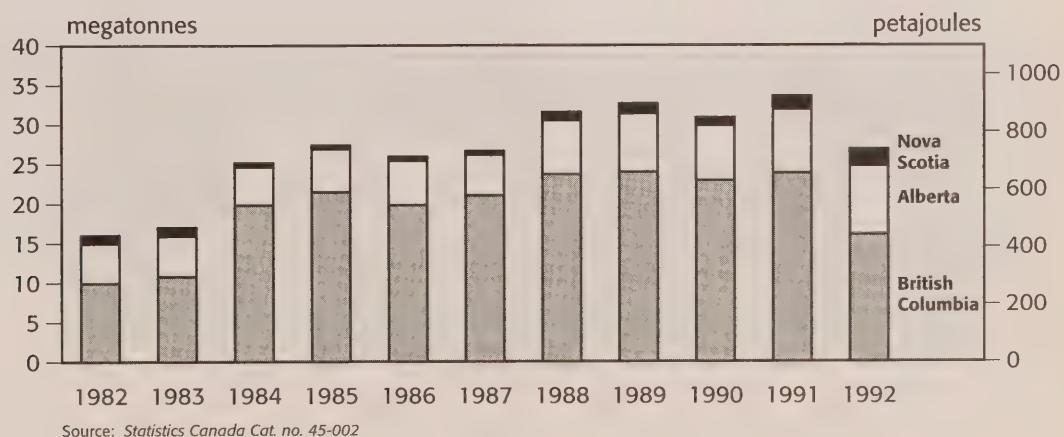
FIGURE 9-4
Metallurgical Coal Export Destinations 1992

Total Exports = 22.4 Megatonnes
(618 Petajoules)

Other
20%

Brazil
5%

15%

South Korea

60%

Japan
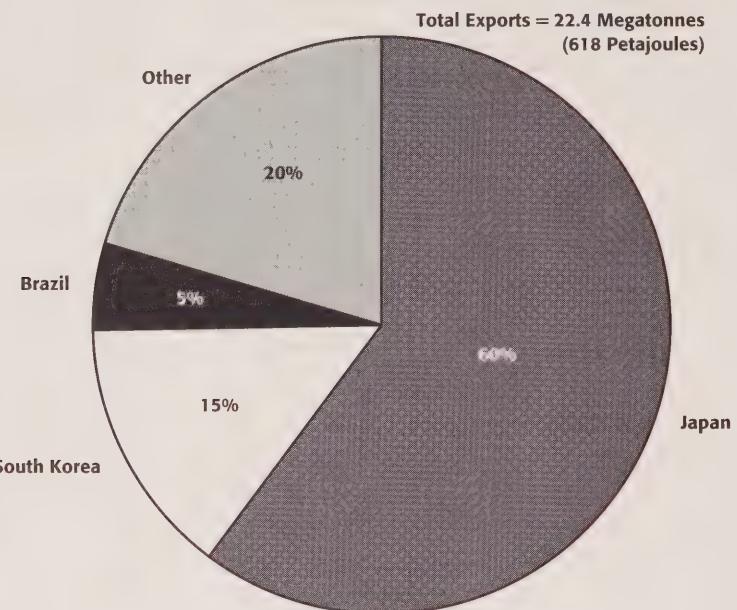
Source: NRCan, *Statistical Review of Coal in Canada, 1992*

FIGURE 9-5
Thermal Coal Export Destinations 1992

Total Exports = 5.0 Megatonnes
(138 Petajoules)

Other
9%

Denmark
21%

25%

South Korea

45%

Japan

Source: NRCan, *Statistical Review of Coal in Canada, 1992*

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
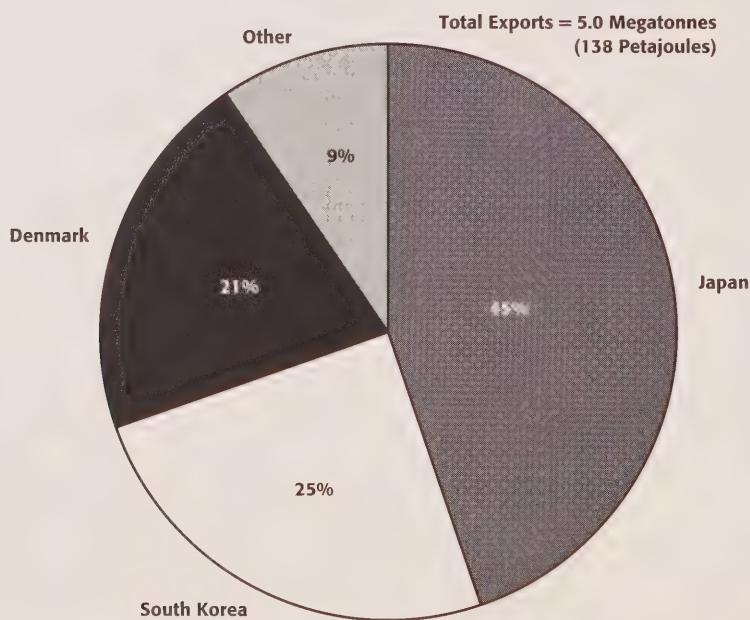
several Canadian coals for injection into the blast furnace.

On a more positive note, the economies and the demand for coal in South Korea and Taiwan should continue to grow strongly. The best opportunity for increased coal exports is Taiwan, which currently receives 18 per cent of its metallurgical coal imports from Canada, and is ideally situated to meet the growing demand for steel in the rapidly developing southeast Asian countries of Indonesia, Thailand, Malaysia and Vietnam.[3] The expansion of blast furnace steel making facilities has commenced and will be completed in the mid-1990s. The increase in steel making capacity will create an opportunity for increased Canadian exports to the region even with increased application of PCI technology.

Canada's export cost for metallurgical coal to the Asian region, which includes the costs of mine operations, capital recovery, rail transport, loading, and ocean transport, is less than that of the United States but higher than that of Australia. Figure 9-6 shows the estimated representative exports costs for Canada and its main competitors in US$1992 per tonne. It should be noted that although costs provided by the International Energy Agency (IEA) are considered to be representative, there is considerable variation between mines within each region. Also there may be some differences in coal quality among regions which should be taken into consideration. For example, although the representative price for Western Canada is about US$58 per tonne, the range is US$49 to $80 per tonne.

The European Market for Metallurgical Coal

The continued rationalization of the European steel industry, and increased use of PCI technology, are expected to reduce European demand for metallurgical coal. However, the anticipated reduction in German coal subsidies during the late 1990s should increase Germany's demand for imported coal. As a result of current German regulations, steel producers are required to purchase highly subsidized domestically produced metallurgical coal or coke. Plans are in place to reduce subsidies gradually. It is expected that pressure from the European Union (EU) will result in further reductions in subsidization of metallurgical coal in the remainder of this decade. Due to Canada's relatively high rail and shipping costs, growth in exports to Europe will depend in part on our ability to reduce costs and on the value which European importers attach to diversification of supply.

Export Outlook for Metallurgical Coal

In view of the changing technologies in the steel industry, and the changing demand for metallurgical coal in the Asian and European markets, Canadian exports are difficult to project. In the short term, we expect exports of metallurgical coal to increase from 22.4 Mt in 1992 to 26.0 Mt in 1995, as Canada recovers part of the export market it lost as a result of financial and labour problems in the coal industry during 1992. From 1995 to 2010, we project exports of metallurgical coal to remain flat at the 1995 level (Figure 9-7).

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3   *Supplement to the Annual Energy Outlook 1993*, Energy Information Administration, U.S. Department of Energy, February 1993, p. 41.

FIGURE 9-6

Estimates of Representative Export Costs for Metallurgical Coal to Japan

Source: *Coal Information 1992*, International Energy Agency, OECD, 1993
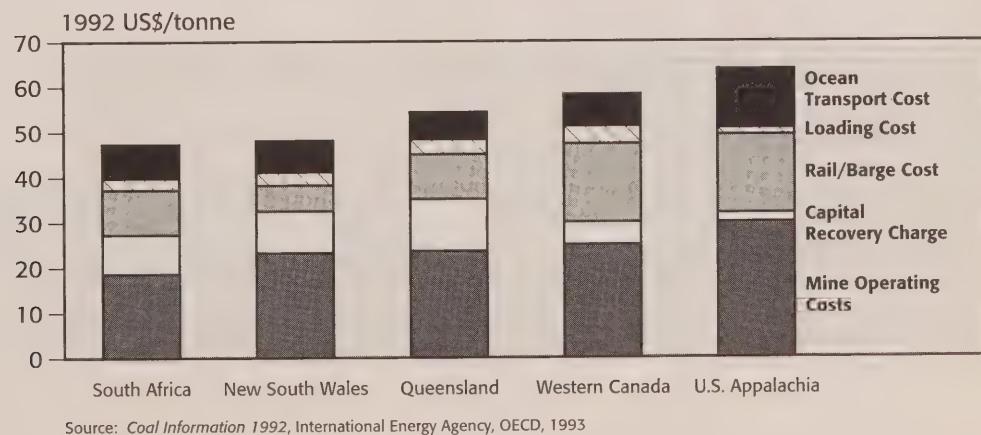
This projection is based on the assumption that Canada's competitive position, as illustrated for the Japanese market in Figure 9-6, will not change significantly during the projection period, except for improvements which have taken place since 1992 as a result of the depreciation in the value of the Canadian dollar and the positive effects of industry restructuring.

Without further change to Canada's competitive position the combined capacity of mines currently producing metallurgical coal will be maintained in the future, while expected economic returns will not allow major capacity increases from new mines.

9.5.2   Thermal Coal Exports

The long term outlook for thermal coal exports is much brighter than that of metallurgical coal due to anticipated growth in requirements for electricity generation, particularly in Asia. However, as for metallurgical coal there are some concerns attributed to thermal coal. A major uncertainty, is the extent to which policies will be adopted to regulate emissions of airborne pollutants and solid wastes from power plants. Of particular concern are emissions of sulphur and nitrogen oxides, which are associated with acid rain, and carbon dioxide, which is a major greenhouse gas.

Growing environmental concerns have resulted in a movement toward the development of clean coal technologies, generally defined as technologies which are aimed at reducing the impact on the environment of coal-fired power stations. Technologies have been developed which offer both environmental and efficiency improvements over the conventional steam cycle.

However, implementation of clean coal technologies will have higher capital costs. Also the large amount of capital tied up in currently productive conventional facilities has been identified as another factor which may limit the implementation of clean coal technology.

Canada is a relatively small exporter of thermal coal, accounting for two per cent of the world thermal coal export market in 1992. The majority of Canada's thermal coal exports have traditionally been destined for the Asian and European markets (Figure 9-5 and Appendix Table A9-3).

The Asian Market for Thermal Coal

Asian demand for thermal coal for use in electricity generation is expected to rise rapidly throughout the projection period.   The IEA expects real economic growth of between 5 and 7 percent in Eastern Asia over the next twenty years.[4] The U.S. EIA predicts that Asian imports of thermal coal will rise at an average annual rate of 4.2 percent from 92 Mt in 1992 to 192 Mt by 2010.[5] In contrast, the Australian agency ABARE predicts that Asian imports of thermal coal will increase at an average annual rate of 7.1 percent for the remainder of the decade. The basis of these predictions is an expectation of strong economic growth resulting in a rapid increase in electricity demand for the Asian region. In 1991 Asia received nearly 80 percent of its thermal coal imports from Australia, South Africa, and China.

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4   *The IEA Energy Outlook to 2010*, International Energy Agency/OECD, May 1993, p. 43.

5   *Supplement to the Annual Energy Outlook 1993*, Energy Information Administration, U.S. Department of Energy, February 1993, p. 42.

FIGURE 9-7
Coal Exports

Source: Appendix Tables A9-4 and A9-5
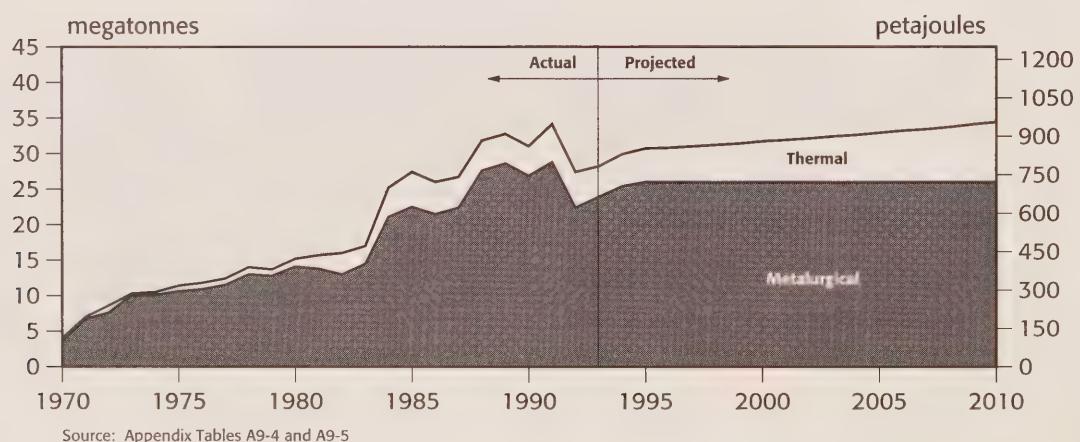
Because of a relatively poor competitive position as illustrated in Figure 9-8, Canada may have difficulty competing with Queensland (Australia), South Africa, and Indonesia in meeting increased demand for thermal coal in the Asian region. As a result, we expect growth in Canadian exports of thermal coal to Asia to be less than the anticipated growth of Asian imports.

The European Market for Thermal Coal

European imports of thermal coal have the potential to rise strongly. Unlike Asia, where increased demand will result from increased power generation, the majority of any increase in European imports of thermal coal will reflect displacement of indigenous supplies. Rising costs incurred in conforming to increasingly stringent environmental regulations and the resulting inter-fuel competition, primarily with natural gas, will limit growth in European demand for thermal coal. Further, the share of European coal consumption met by imports is expected to rise when some of the European mines, especially in Germany, are closed following large reductions in government subsidies as currently proposed by the European Union. Therefore, as with metallurgical coal exports to Europe, growth in thermal coal exports to Europe will depend in part on cost competitiveness of Canadian coal and on the value which European importers attach to diversification of supply.

Export Outlook for Thermal Coal

Canada's exports of thermal coal are expected to be approximately 4.3 Mt in 1993, a decline of 19 per cent from 1992. The sharp decline reflects reductions in exports from both British Columbia and Nova Scotia. Exports from British Columbia are down substantially due to labour and financial problems, while the Westray explosion in mid 1992 has indirectly resulted in a 0.5 Mt per year reduction in Nova Scotia exports.

Based on the anticipated growth of exports into the Asian market and some potential, although uncertain, growth in the European market, Canadian exports of thermal coal are projected to grow at an average annual rate of four percent from 1993 to 2010 (Figure 9-7).

9.6   COAL IMPORTS

In 1992, 26 percent of domestic coal demand was met from imports, all of which came from the United States. Of the 12.8 Mt imports, 12.4 Mt were imported into Ontario and 0.4 Mt into Quebec (Table 9-4). Thermal power generation in Ontario accounted for 7.5 Mt of the imports with the remainder being metallurgical coal for coke production. Imported coal accounted for 71 percent of Ontario Hydro's requirements for thermal coal. Coal imports into Quebec were mainly used for titanium smelting, electrode production for aluminum smelting and a small amount was used for cement production.

Our projections of coal imports for both the Current and High Tech cases can be found in Figure 9-9. Following a decrease in 1993, thermal coal imports are projected to substantially increase in both cases until about 2007. In the Current Tech case thermal coal imports should continue to increase and reach 18.5 Mt by 2010, while in the High Tech case, thermal coal imports are expected to decrease from 16.2 Mt in 2007

FIGURE 9-8
Estimates of Representative Export Costs for Thermal Coal to Japan

Source: *Coal Information 1992*, International Energy Agency, OECD, 1993
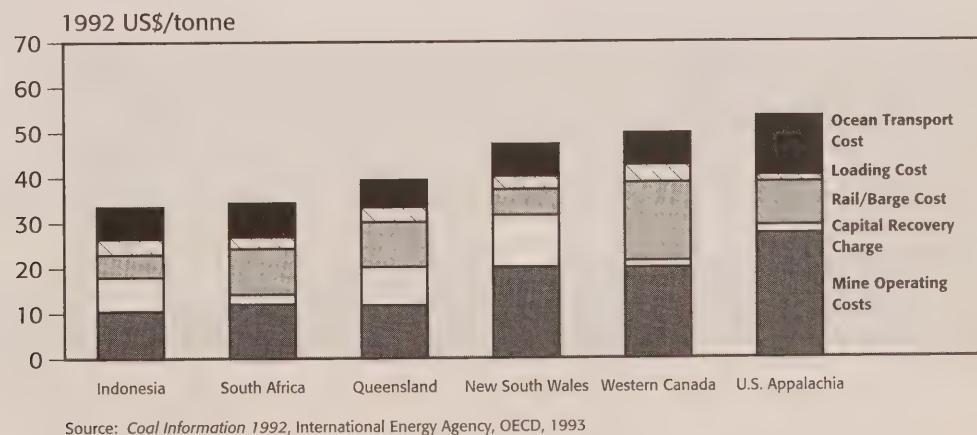
to 14.6 Mt by 2010. This is caused by the fact that lower gas prices in the High Tech case should lead to the substitution of coal with natural gas for electricity generation. Ontario will receive most of the thermal coal imports with small quantities projected for New Brunswick and a minor amount for Québec.

Metallurgical coal imports, which are mainly used in the Ontario steel industry, are expected to grow from 4.8 Mt in 1992 to 7.2 Mt in 2010, for both the Current and High Tech cases.

9.7   COAL PRODUCTION

Canada's coal production has increased 53 per cent over the last ten years (Figure 9-10). In 1992, Canadian coal production totalled 65.3 Mt, down 8 percent from the 71.1 Mt record production set in 1991. Production of thermal coal during 1992 was 43.5 Mt and metallurgical coals accounted for 21.8 Mt of the total (Table 9-5).

British Columbia was the only province that showed a decline in production for 1992. Its production, which was all bituminous, declined by 8 Mt to 17 Mt. This was due to a combination of labour problems and a mine closing which affected three mines. Two of the troubled mines were involved in a bankruptcy and are now operating under new ownership. Approximately 95 percent of British Columbia's coal production was exported which makes British Columbia Canada's largest coal-exporting province.

Alberta was the largest coal producer in 1992, producing mostly subbituminous coal. Total production increased by 1.0 Mt to 33.5 Mt consisting of 23 Mt subbituminous and 10.5 Mt bituminous. Almost all of the subbituminous production was used for power generation and most of the bituminous production was shipped to export and Ontario markets.

For Saskatchewan, which produces only lignite coal, 1992 production increased by 12 percent to 10 Mt. Approximately 87 percent of production was used within

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TABLE 9-4

Coal Imports in 1992

	Megatonnes	Petajoules	Percent by Volume
Ontario	12.4	359.9	97
Québec	0.4	11.7	3
Canada	12.8	371.6	100

Source: Statistics Canada, cat. no. 57-003.

FIGURE 9-9

Coal Imports – Current and High Technology Cases
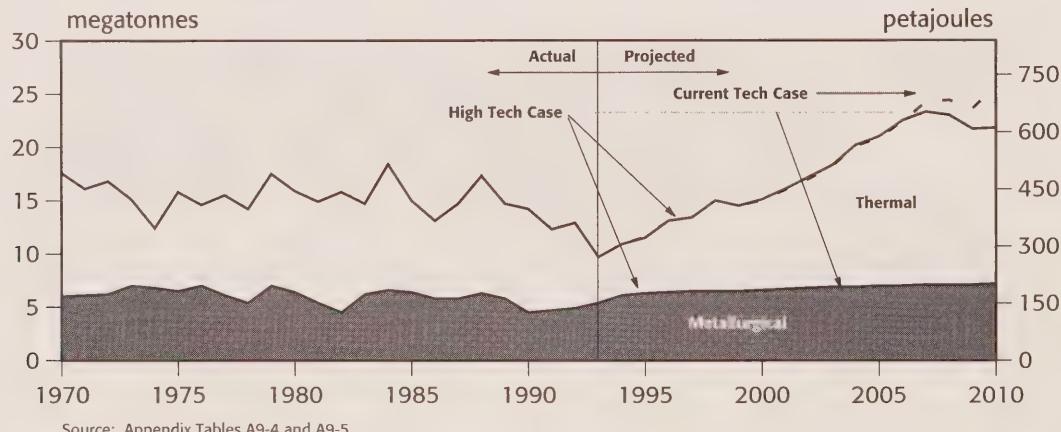
Source: Appendix Tables A9-4 and A9-5

the province to generate electricity with the rest being shipped to Manitoba and Ontario thermal markets.

New Brunswick produced 0.4 Mt of bituminous coal which was used within the province for power generation.

In Nova Scotia, 1992 coal production increased slightly to 4.5 Mt despite three mine closings caused by an explosion at one mine, a fire followed by flooding at a second mine and flooding of the third mine. All of the production was bituminous grade and was delivered in nearly equal portions to local and export markets.

In spite of the production decline in 1992, historical growth rate of Canadian coal production is expected to be maintained during the projection period. This increase in coal production in both Current and High Tech cases is due to increasing demand for thermal coal used for power generation in both the export and domestic markets. We expect total production to increase from 65.3 Mt in 1992 to 90.9 Mt in 2010 in the Current Tech case and 81.8 Mt in the High Tech case (Figure 9-10). This difference in coal production can be attributed to a large difference in future natural gas prices between the two cases. In the Current Tech case, higher natural gas prices are expected to result in more coal being used for thermal applications, such as steam raising for bitumen recovery, and to remain the fuel of choice in some provinces for base load electricity generation. On the other hand, relatively lower natural gas prices in the High Tech case favour the use of natural gas for the above applications.

9.8   CONCLUDING COMMENTS

Our projections show considerable growth in domestic coal demand for power generation in the Current Tech case and somewhat slower growth in the High Tech case. Power generation demand will be met by increasing both domestic production and imports. Domestic metallurgical coal demand will show moderate growth which we assumed to be met entirely by imports.

Coal exports, which are more difficult to predict, are projected to grow slowly, with most of the growth expected in the thermal coal market. The use of coking coal in the Asian metallurgical coal market is expected to continue but the use of PCI technology will take up the available market growth. Metallurgical coal users prefer to maintain a diverse supply portfolio which could benefit Canada's coal exporters. The world market for thermal coal is expected to keep growing which, even with new supply sources, should provide some room for expansion of Canadian thermal coal exports.

In summary, we project growth in Canadian coal production to satisfy increases in both domestic and export demand. However, this growth is dependent on our coal industry's ability to continue to be price competitive with other sources of coal, on the desire of buyers in export markets to maintain a diversity of suppliers, and on the continued environmental acceptability of coal. The relationships between supply and demand for both the Current and High Technology cases, which reflect different natural gas price projections, are shown in Figure 9-11.

FIGURE 9-10
Coal Production – Current and High Technology Cases
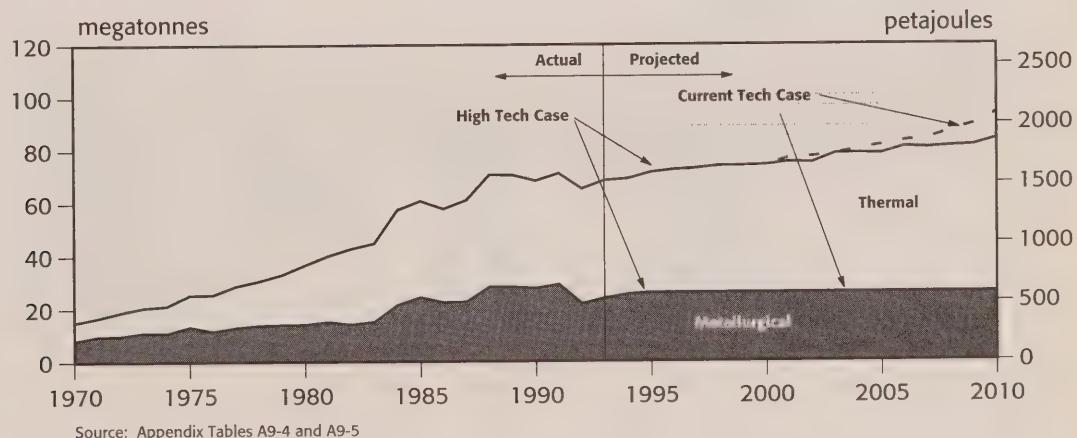
Source: Appendix Tables A9-4 and A9-5

TABLE 9-5

Coal Production by Province and Class in 1992

Province	Class	Megatonnes	Percentage of Total Production	Petajoules	Percentage of Total Production
British Columbia	Bituminous				
	Thermal	2.4	4	74	5
	Metallurgical	14.4	22	440	29
Alberta	Bituminous				
	Thermal	4.1	6	125	8
	Metallurgical	6.4	10	194	13
	Subbituminous	23.0	35	421	27
Saskatchewan	Lignite	10.0	15	150	10
New Brunswick	Bituminous				
	Thermal	0.4	1	11	1
Nova Scotia	Bituminous				
	Thermal	3.5	5	100	7
	Metallurgical	1.0	1	27	2
Canada	Bituminous				
	Thermal	10.4	16	310	20
	Metallurgical	21.8	33	662	43
	Subbituminous	23.0	35	421	27
	Lignite	10.0	15	150	10
	Total	65.3	100	1 543	100
Canada	Thermal	43.5	67	881	57
	Metallurgical	21.8	33	662	43

Source: *Statistical Review of Coal in Canada:1992*, Energy Mines and Resources, Canada, 1993.

FIGURE 9-11

Coal Supply and Demand in Canada – Current and High Technology Cases

Source: Appendix Table A9-5

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010

Chapter 10
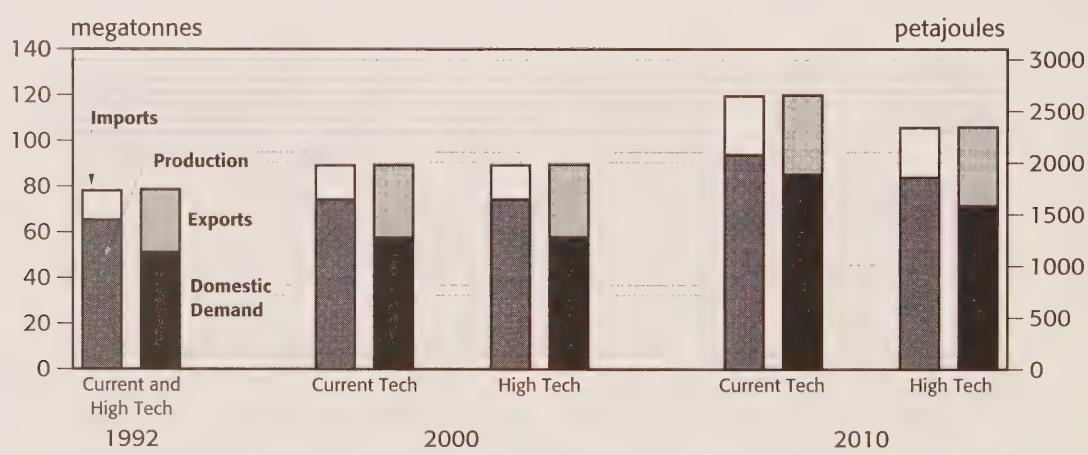
ALTERNATIVE AND RENEWABLE ENERGY

10.1   INTRODUCTION

Alternative and renewable energy sources include: biomass (i.e., wood, wood waste, spent pulping liquor, municipal solid waste); water (i.e., small hydro); wind; solar radiation; and geothermal and tidal energies. These energy sources can be classified into two general applications, electricity generation and/or space and water heating. In addition, wind can be utilized to power water pumping systems. The technologies associated with the sources include: biomass incineration, small hydro electricity generation, wind-powered electrical generators, passive solar space heating, active solar heating, photovoltaic electricity generation, ground source heat pumps (GSHPs) and tidal electricity generation.

In our initial consultations on the Supply and Demand Report, representatives from the energy industry as well as several government departments expressed an interest in the subject of the use and development of alternative and renewable energy. Therefore, this report presents a more in-depth review, as compared to previous reports, of the renewable energy sources. We will use the term renewable energy throughout this chapter, to encompass alternative and renewable energy.

The quantity of energy ultimately available from renewable resources, although not described here in detail, has been estimated in the order of several hundred times the current levels of total energy use. However in most cases, the economically viable quantity of energy which is available from renewable resources is smaller and varies considerably with location. In this report we have assumed that based on current and projected levels of use of renewable energy sources, their consumption will not be constrained by availability of supply.

Currently, renewable energy sources play a small, but locally important role in the overall Canadian energy supply. In 1992, they accounted for about six percent of the total Canadian energy demand; however, the regional market shares vary greatly, accounting for up to 18 percent of British Columbia's and Territories' end use energy demand and as little as two percent in Alberta. Generally, the supply costs of renewable energy sources are high relative to the end use prices for conventional energy in the residential, commercial and industrial energy sectors. However, several renewable energy sources have found niche markets, where they may be cheaper than conventional energy sources, or where conventional sources may not be available.

This chapter contains estimates of current levels of energy consumption supplied by renewable energy (see Chapters 4 and 5), and provides estimates of its future use. Projections of future energy consumption which will be met by renewable sources in the end use level and the primary level are summarized. Analysis of current and future economic competitiveness of specific renewable energy technologies (excluding GSHPs and passive solar space heating), relative to end use conventional energy prices is also described in this chapter. Our end use conventional energy prices (Chapter 3), are compared to renewable energy sources' supply costs which were prepared by the Hickling Corporation for the Department of Natural Resources Canada (NRCan), and can be used as the summary indicator of cost competitiveness.[1] Potential future levels of use of renewable energy based on Hickling's assessment of supply cost data, and possible future developments which could lead to important changes to the current economics, are also presented.[2]

This analysis does not suggest that economically attractive renewable energy technologies could be used to displace conventional fuels on a large scale. Rather, it identifies several niche market applications where it is economically attractive to utilize renewable energy technologies. Furthermore, the expected utilization of renewable energy in these markets will vary considerably across Canada, due to differences in regional energy demand patterns, and the availability and costs of the conventional and renewable energy sources.

1   Hickling Corporation. *Cost and Performance Data on Renewable Energy Technology: Input to OERD's Energy 2020 Model. Technical Background Paper.* Prepared for: Office of Energy Research and Development. Energy, Mines and Resources Canada. Ottawa, Ontario. March 23, 1992.

2   Various passages and data presented in this chapter are extracted from the following document:

Background Report, Renewable Energy Policy Review. Policy Development and Analysis Division, Efficiency and Alternative Energy Branch, Energy, Natural Resources Canada, May 1994.

10.2 ENERGY SUPPLY COSTS, PRICES AND TECHNOLOGICAL DEVELOPMENT

For the purpose of developing projections of consumption of renewable energy, we compiled supply costs for several renewable energy sources, and compared them with our conventional energy prices. Following subsections contain results of the analysis and general discussion of the individual renewable energy sources. Also presented here are some qualitative assessments of possible future developments of renewable energy technologies, which could lead to important reductions in their supply costs.

In projecting end use conventional energy prices (Chapter 3), we developed end use market prices because our primary objective is to estimate demand and supply of energy in the context of anticipated market price behaviour. We have not made an attempt to evaluate the social costs associated with the use of renewable or conventional energy sources. The current relationship between the supply cost of renewable energy and end use conventional energy prices could shift considerably if energy were priced on the basis of social costs, rather than on a commercial or market basis. A summary of the current and future efficiency-adjusted end use conventional energy prices, for both Current and High Technology Cases, is shown in Appendix Table A10-1.

The supply cost of a renewable energy technology represents the average cost of supplying one unit of energy from this technology, at the end use level, over its expected life. It is calculated by dividing the present value of all costs by the present value of energy produced (measured in dollars per gigajoule). In Hickling's analysis all technologies are evaluated over their expected lives using a seven percent real discount rate, and all costs are measured in constant 1992 dollars.[3]

The calculated supply cost for a specific renewable energy technology includes estimates of capital, operation and maintenance costs per unit of energy. It is also dependent on factors such as system efficiency and useful life. Since there is a large variability in estimates of these factors for any given technology, Hickling Corporation developed a supply cost range for each technology rather than point estimates. For electricity supply technologies Hickling Corporation did not take into account the transmission costs required to transport electricity to the local market, because it is assumed that the renewable energy source is located close to demand. A summary of their results, which we have converted to constant 1993 dollars is shown in Appendix Table A10-2.

Data used in Hickling's analysis were obtained from a variety of sources. Initially, the data were acquired from existing reports prepared for NRCan, Ontario Hydro and the Ontario Ministry of Energy. Following the literature search, data were updated through communication with industry, associations and representatives from governments and utilities. In addition, efforts were made to obtain data from recently installed renewable energy projects in Canada.

While the results are based on extensive data research, it is important to remember that the results are subject to uncertainties. In the area of renewable energy there are few systematic, regular data collection exercises that provide a reliable database for this type of analysis. Therefore, even though the analysis presented is based on the best data available, there remains a potential for improving the reliability (in absolute terms and also across technologies), regularity and homogeneity of these data.

10.2.1 Wind

Applications of wind energy include electricity generation (grid and remote) and water pumping. Canada currently has two test sites: the Atlantic Wind Test Site, to assess electricity generating wind turbines; and the Alberta Wind Test Site, for water pumpers. These technologies have already found some commercial applications, namely, about 8 MW of installed capacity, as well as approximately 1 000 water pumpers installed in Alberta, Saskatchewan and Manitoba. The current capital costs of the wind turbines range from $1 200 to $1 500 per kilowatt for 150 to 500 kW systems, assuming an average annual wind speed of 6 to 7 meters per second (m/s), or 22 to 25 kilometres per hour (km/h).

The supply costs of wind energy systems range from $14 to $28 per gigajoule (or 5 to 10 cents per kilowatt hour), and are competitive with residential electricity and oil, and commercial electricity supply. The high end of the range assumes less favourable sites (eg. lower wind speeds). However, these sites can be economic in remote areas where the competing diesel-fired generators produce electricity at a cost of up to $125 per gigajoule. Based on our projected conventional fuel prices, wind energy will remain competitive with the sources identified above, but will not be able to compete

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3 In our evaluation of conventional energy supply costs we have used an eight percent real discount rate. We do not believe this will invalidate the comparison of conventional and renewable energy prices.

with natural gas in any of the sectors in either the Current or High Tech Cases.

By the year 2010, one estimate suggests that the contribution of wind power could grow to 68 MW of installed wind capacity in remote communities and 102 MW in main grids. This estimate is based on constant, in real terms, utility power purchase rates ("buy-back" rates). It is assumed that individual wind turbines or large wind farms are privately owned and operated with the power contracted to the power utility. Also assumed is a potential market for up to 40 000 water pumping wind systems in Western Canada.[4]

Future reductions in capital cost could notably improve the economic competitiveness of wind energy systems. Several low cost machines have been installed at a test site near Pincher Creek in Alberta. The developer of one of these machines projects installed costs in the order of $750 per kilowatt. This reduction in supply costs has been considered in the projection of installed capacity, but it has been assumed that no further improvements in performance will occur over the study period. This may be conservative, as recent design trends elsewhere indicate that new airfoils, increased turbine sizes, and improved control systems may increase energy production by as much as 25 percent for utility-scale wind turbines without increasing the overall costs.

10.2.2 Solar

The use of solar radiation as an energy source can be classified into three distinctive components: Passive Solar, Active Solar and Photovoltaic systems. In general, the limited use of solar applications in Canada is a function of high costs, and relatively low and intermittent levels of solar radiation in Canada.

The problem with using solar energy for space heating is that it is most abundant when it is needed least. In June the monthly average of solar radiation received is almost double the yearly average, and indeed the far north sees the highest values in the country. In December, however, typical values are less than one-third the yearly average. Generally, latitude is a good indicator of solar radiation, but in areas of frequent cloud cover, notably the west and east coasts and the Great Lakes areas, radiation levels are below those that would otherwise be expected.

10.2.2.1 Passive Solar

Passive solar is a building design practice rather than a specific product. Passive solar design utilizes solar heat and light to maintain a comfortable indoor climate and offset the need for conventional energy. This is accomplished by arranging and using the various components of a building (essentially those traditionally present and "paid for") to make optimum use of solar energy. It may involve building layout, exposure, and window placement. By definition, it involves a studied arrangement to maximize net solar utilization. In addition, it usually involves the use of active mechanical ventilation and air-handling inside the building to distribute and store the heat, for release as needed.

The benefits of passive solar are very difficult to measure; therefore, any quantitative estimates of its contribution are uncertain. Passive solar contribution to the building energy in the existing residential and commercial building stock was estimated at about 48 PJ per year in 1988, or about 4 percent of the total building space heating energy requirement in Canada.

By the year 2010, it is estimated that the "reasonably achievable market potential", developed through scenarios of market penetration by the available and emerging technologies, will be 131 PJ per year.[5]

Passive solar technologies, both existing and emerging, can add to the energy performance of buildings regardless of building shape, layout, orientation and "sun rights". Four emerging passive solar technologies have been identified and evaluated for their additional potential to conserve energy in Canada's existing residential and commercial buildings, as well as in new construction to the year 2010. These technologies are: high performance windows, daylighting, integrated mechanical systems, and thermal storage. Further technological progress could increase the potential of passive solar applications above the estimates provided here.

10.2.2.2 Active Solar

Active solar technologies involve collection and direct conversion of solar radiation into thermal energy. This energy can be used to heat fluids, for direct heating applications, or to drive turbines for electricity generation.

For Canada, the most cost-effective application of active solar technology is for low temperature heating

4   Rangi, R., J. Templin, M. Carpentier, D. Argue. *Canadian Wind Energy Technical and Market Potential*. Efficiency and Alternative Energy Branch, Energy, Mines and Resources Canada, Ottawa, Ontario, October 1992.

5   Parekh, A., R.E. Platts, Scanda Consultants Ltd. *Passive Solar Potential in Canada: 1990 – 2010*. DSS Contract No. 69SZ.23216-8-9043. Efficiency and Alternative Energy Technology Branch, Energy, Mines and Resources Canada, Ottawa, Ontario, 1990.

applications such as ventilation air heating for industrial buildings, water heating for fish farms, and pool heating. Other applications including space heating systems, and industrial, domestic and commercial hot water systems are less cost-effective in Canada because they are required to provide higher operating temperatures.

In 1992, there were approximately 12 000 residential solar water heating systems and 170 commercial and industrial solar hot water systems in use. Approximately 20 000 m^2 ($1m^2=1kW$) of industrial ventilation air heating systems have also been installed over the past few years. Total current contribution of active solar energy is estimated to save 110 MW, compared to a total Canadian generating capability of 105 GW.

With supply costs in excess of $20 per gigajoule, solar domestic hot water systems are generally not economically attractive compared to residential electricity, oil and natural gas systems. This situation is not expected to change by the year 2010. Currently, the greatest impediment to improvement are the high capital costs, in the range of $450 to $580 per kilowatt. Solar pool heating systems, with supply costs between $14 and $25 per gigajoule, can be cost competitive with residential and commercial electricity and oil systems. Based on our projected conventional fuel prices, solar pool heating systems will continue to be competitive with those fuels.

Solar industrial ventilation air heating systems, with supply costs ranging from $6 to $12 per gigajoule, are economically attractive compared to electricity based systems, but are not competitive in comparison with the oil and natural gas systems. However, by the year 2010 the price of natural gas in the industrial sector is projected to reach a range of $6 to $10 per gigajoule, under the Current Tech Case, in turn allowing the solar energy systems to become competitive with natural gas systems.

For the year 2010 one estimate suggests that 14 PJ of energy demand will be displaced by active solar energy. This projection is based on an estimated total energy demand in the potential market applications of about 720 PJ per year. It is also estimated that if the cost of externalities arising from environmental and other external economic factors were included in the price of conventional fuels, the contribution of active solar energy could increase to 21 PJ in 2010.[6]

The growth in the active solar energy market is projected to be very slow initially and then to rise exponentially to the year 2010, as lower costs of solar technologies will make the solar option more attractive,

and as consumers become more aware of the availability and reliability of the technologies. The expected penetration of solar heating varies considerably across Canada due to differences in housing stock and the availability and cost of conventional and solar energy sources. The greatest contribution of solar heating in terms of provincial market share is expected in Saskatchewan at over three percent, due to the relatively high cost of electricity and on average the best solar resource availability in Canada. This is followed closely by New Brunswick, Nova Scotia and Prince Edward Island, all at about 2.5 percent, since the energy prices in Atlantic provinces are among the highest in Canada. For Newfoundland, the market share is projected to be less than one percent due mainly to the low solar resource availability in the province.

The costs of active solar technology can be reduced as a result of lighter-weight solar collector designs, better solar collector surfaces, improved performance-to-area ratio of heat exchangers, new piping materials and improved manufacturing techniques. Capital costs of water heating systems could be reduced by as much as 40 percent through technological improvements over the next 10 to 15 years.

One particular technology dominates the industrial ventilation air heating applications. It is expected that the continuing development of this technology could lead to a 15 percent reduction in capital cost and a 15 percent improvement in performance over the next five years.

10.2.2.3 Photovoltaic Sytems

Photovoltaic (PV) systems produce direct-current (DC) electric power from solar energy, using semiconductor materials. Systems consist of an array of solar cell modules, a mounting structure, storage unit, a DC to alternating-current (AC) conversion system, back-up power source, and, if connected to a utility, a grid connection. The power and efficiency of the system is dependent on the cell material.

In 1992, installations provided less than 1 MW to Canadian energy supply (compared to a total Canadian generating capability of 105 GW), with most applications off-grid. One of the largest off-grid installations is a 10 kW module connected to a diesel

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6   Carpenter, S.C., Caffell, T., McClenahan, D. and A.M. Carpenter *Active Solar Heating in Canada to the Year 2010*. Efficiency and Alternative Energy Technology Branch, Energy, Mines and Resources Canada, Ottawa, Ontario, 1992.

powered system in a native community at Big Trout Lake in northern Ontario. The Canadian Coast Guard is the largest user of photovoltaic systems in Canada, with over 3 000 installations used primarily as supply sources for navigational buoys.

PV technology, with electricity supply costs over $150 per gigajoule, is clearly not economically attractive in comparison to on-grid electricity generated using conventional fuels. Furthermore, the technical performance of PV systems for application in Canada is constrained by relatively low annual amount of solar radiation and very high seasonal variability of the solar resource. However, because of their high reliability and low maintenance, PV systems are particularly suited to non-grid or remote applications such as telecommunications, lighting, or monitoring devices which utilize relatively small amounts of electricity. A recent Mobil Oil Canada project in central Alberta utilizes solar energy to run the equipment the company uses for cathodic protection to prevent corrosion in its wells and pipelines.

Advances are being made with new semiconductor materials[7], and based on these anticipated technological advances, the cost of modules could fall to less than 10 percent of current costs, and the overall system cost reduction could be in the order of 50 to 75 percent.

International researchers are also looking at a completely new technology that, if successful, will substantially reduce the cost of PV electrical energy to 3 to 4 cents per kilowatt peak hour (kWph). This technology uses a titanium dioxide film coated with a photosensitiser to convert sunlight to electricity, and it could be commercially available in the next five years.

In addition to expected gains in performance, the reliability of PV-powered special controls and devices has opened up new end use markets. As a result of these advances the utilization of PV technology could increase, but will remain relatively small compared to the total Canadian generating capability.

10.2.3 Small Hydro

Projects or plants are identified as "small hydro" if the hydraulic turbines and generators that convert the potential and kinetic energy of water to electric energy generate less than 20 MW.

Potential developments for small hydro include: sites with existing dams, sites where existing technology requires repair and rehabilitation, sites which require full dam construction, and micro-hydro (less than 100 kW).

In 1992, the total installed capacity of small hydro development in Canada was about 800 MW, compared to a total Canadian generating capability of 105 GW.

Non-utility generators, including companies engaged in resource development as well as isolated communities, account for the major portion of small hydro energy production.

Projects associated with existing dam sites, including those sites which are currently inoperative because they require repair and rehabilitation, can be economically attractive, with supply costs ranging from $7 to $23 per gigajoule. Projects associated with sites which require full dam construction, with capital costs ranging between $3 000 and $5 000 per kW, are generally not economically attractive (i.e., supply costs ranging from $12 to over $36 per gigajoule). Micro-hydro systems, with electricity supply costs between $6 and $17 per gigajoule, can be cost competitive with residential fuel prices at the most favourable sites (i.e., heads over 5 m, with reasonable flow rates), mostly in rural areas.

By the year 2010, one estimate suggests that the commercial potential for small hydro developments will be 1 950 MW of new installed capacity, with an energy output of approximately 11 TWh per year, or about 1.6 percent of the total projected generation in Canada (678 TWh per year). This estimate is based on current buy back rates as per the avoided cost of the particular utility. However, if the utilities, in recognition of possible environmental benefits associated with the use of renewable energy, were required to pay a premium of 2 cents per kilowatt hour for electricity generated using renewable resources, the estimated small hydro contribution could grow to 2 890 MW of new installed capacity, with an energy output of approximately 16.5 TWh per year, or about 2.4 percent of the total projected generation in Canada.[8]

The technology for small hydro is now considered generally mature. However, cost reductions can be expected to occur in small hydro electrical components and in simplifying mechanical designs. Small hydro electrical equipment has undergone major advances in technology over the past decade, where control functions have been taken over by programmable controllers and computers.

There are some opportunities for small hydro developments both in the utility market and, increasingly, in the remote community market.

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7   The semiconductor materials include: copper-indium-diselenide, ribbon-silicon, cadmium-telluride, and thin-film-silicon.

8   Izsak, G.L., Guthrie, B.M., Birkenheier, T.L., *Non-Conventional Generation Technologies and the Canadian Renewable Energy Technology Program.* Alternative Energy Division, CANMET, Energy, Mines and Resources Canada, 1992.

Developments are likely to occur at sites with existing dams that are relatively close to the grid. Small hydro sites requiring dams may be cost competitive if the project size is in the 15 to 20 MW range and at remote sites, where diesel generated electricity can cost up to $125 per gigajoule. The market dynamics for the micro-hydro technology based systems are very different from those for other small hydro applications, as the technology is bought and most often installed by individual home-owners.

10.2.4 Biomass

Biomass, which includes waste products from forests and mills, wood from plantations, as well as agricultural products and wastes, municipal waste and spent pulping liquor, can be used as an energy source. Methods for the production of bioenergy include thermochemical conversion to produce gaseous or liquid fuels, biochemical conversion using fermentation to produce ethanol, and biomass combustion. The most common use of biomass at this time is in a combustion process for heat. Cogeneration, or the simultaneous production of heat and electricity, is becoming more widespread. In 1992, about 900 MW of biomass-based cogeneration facilities existed in Canada.

In addition to the residential wood burning market, the Canadian market for bioenergy is composed of over 8 000 commercial and industrial users, with the pulp and paper industry representing a major portion of the latter.

Residential space heating using wood can be economically attractive in a rural setting where the wood supply costs are low ($3 – $12 per gigajoule) and natural gas is not available, for example in rural areas and the Atlantic provinces. However, these systems are not as attractive for urban users, where the wood supply costs are much higher ($12 – $42 per gigajoule), and where wood may be inconvenient to handle and store. Commercial and industrial systems can be economically attractive depending on the individual system that is required. Supply costs for these systems range from $3 to $17 per gigajoule, which makes them competitive with conventional fuels in areas where they have access to a low cost supply of biomass.

By the year 2010, one estimate suggests that the commercial potential for biomass developments will be 1 350 MW of new installed electrical capacity, with an energy output of approximately 9 TWh per year, or about 1.3 percent of the total projected generation in Canada (678 TWh per year). This estimate is based on current buy back rates as per the avoided cost of the particular utility.

However, if the utilities, in recognition of possible environmental benefits associated with the use of renewable energy, were required to pay a premium of 2 cents per kilowatt hour for electricity generated using renewable resources, the estimated biomass contribution could grow to 4 670 MW of new installed capacity, with an energy output of approximately 31 TWh per year, or about 4.6 percent of the total projected generation in Canada.[9]

The supply costs of bioenergy are sensitive to the availability of a low cost source of biomass. For example, the supply costs of Municipal Solid Waste (MSW) projects are very sensitive to the tipping fee, or the price paid per tonne for the avoided cost of landfill. The tipping fee varies considerably by region depending on the availability and cost of landfill sites; for example, the fee will be higher in a large urban centre, as compared to a small one.

Interest in the thermochemical and biochemical conversion technologies is increasing. Specific examples of these technologies include the production of bio-oils and certain chemicals from biomass via thermochemical conversion and the production of ethanol through biochemical conversion. Canadian work on alcohol fuels is currently focussed on advancing the use of methanol and ethanol to blend with or replace gasoline and diesel fuel. Research is also being conducted on the use of enzymes to produce ethanol from wood. Interest is also increasing in Municipal Solid Waste burning in some metropolitan areas of Canada; however, production of energy is presently restricted because of environmental concerns regarding incineration.

Areas offering opportunities for cost reductions include more economic harvesting and collection systems, and development of uniform fuels sources with high energy density through improved handling, storage and pretreatment systems.

10.2.5 Geothermal

Geothermal energy can be derived from "hot spots" in the earth's crust, which originate mainly from radioactive decay, but also from the conduction of heat from the planet's core. There are four types of geothermal resources: hydrothermal (hot water), geopressured (confined reservoirs with high pressure,

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9   Izsak, G.L. Guthrie, B.M., Birkenheier, T.L., Non-Conventional Generation Technologies and the Canadian Renewable Energy Technology Program. Alternative Energy Division, CANMET, Energy, Mines and Resources Canada, 1992.

caused by the weight of overlying sediments), hot dry rock and magma. While most geothermal resources will eventually be replenished by the flow of heat to the surface of the earth, these resources can be depleted in a matter of decades and hence require proper management strategies.

In 1992, there were no geothermally-based electric plants operating in Canada, and there were only a few isolated sites where warm water is used for space heating.

The results of the economic analysis indicate that geothermal energy, with supply costs of $13 to $21 per gigajoule, could compare favourably with oil and electricity in the residential sector, as well as with electricity in the commercial sector.

Canada has little experience with this technology, and there is no established trend of technological progress on which to base a projection for future supply cost reductions. Furthermore, a complete estimation of geothermal resources in Canada has not been undertaken. Most parts of the country have been examined only in a cursory manner.

As economics and resource limitations are the principle factors in this energy source's potential, the opportunity at this time is very limited. However, there are possible site-specific opportunities, principally in British Columbia, with two projects now in the early stages of development in the Meager Creek/Lillooet area north of Vancouver. For example, the size of one proposal for a geothermal electricity facility on Meager Creek is 260 MW.

10.2.6 Ground Source Heat Pumps (GSHPs)

The thermal energy just below the earth's surface is estimated to exceed 2 000 times the total current and proven reserves of all other energy sources on the planet combined. A ground source heat pump uses the earth and/or groundwater as the source of heat in winter and as a "sink" for heat removed from the home in summer. For this reason, ground source heat pumps have come to be known as earth energy systems (EESs). Heat is removed form the earth through a liquid, such as groundwater or an antifreeze solution, upgraded by the heat pump and transferred to indoor air by air ducted or hydronic (water distribution) systems. During summer months, the process is reversed, heat is extracted from indoor air and transferred to the earth through the groundwater or antifreeze solution.

Earth energy can be recovered from the water of an aquifer (underground body of water). In an open loop system, water is pumped from an aquifer, the natural heat is extracted, and cool water is discharged to a suitable above-ground body of water. In a closed loop system, a plastic pipe filled with a recirculating heat transfer liquid is buried in a shallow trench or in vertical walls close to the building.

In 1992, there were an estimated 27 000 GSHPs installed in Canada. This corresponds to 351 MW of capacity based on an average installed residential system of 13 kW in size. Although the initial cost of a GSHP is generally at least twice the cost of a gas, electric or oil-fired furnace with add-on air conditioning, the GSHP has a number of distinct advantages. Because they have lower operating costs than conventional heating systems, in some cases they may be the cheapest option when all costs are accounted for over the lifetime of the system. They can provide space heating, cooling, dehumidification and domestic hot water at a fraction of the operating cost of using conventional means. They are reliable and have a long service life, and are based on a technology that is environmentally sound (i.e., most of the energy used in a GSHP is renewable solar energy that is stored in the earth).

A GSHP installation at a commercial bank in Baie-Ste-Anne, New Brunswick, was completed in 1990. The incremental cost of the GSHP over a conventional system was $1 400. While the cost to heat and cool the building and provide hot water for one year amounted to $1 150, New Brunswick Power estimated that it would have cost approximately $2 875 to provide the same service with a conventional system.

Some concerns have been expressed over possible pollution associated with the antifreeze in the circulating fluid used in closed loop systems. In general, such concerns can be addressed through the use of readily available non-corrosive and bio-degradable antifreeze fluids. Also some installation limitations may exist, depending on local soil conditions and zoning laws.

GSHPs are becoming more widely used as the environmental, economic and energy security advantages are recognized. In addition, GSHPs are now a high priority amongst electrical utilities involved in energy conservation initiatives. A number of these utilities offer a rebate with the installation of an GSHP in areas not serviced by natural gas.

GSHPs are one of the fastest growing technologies in the heating, ventilation and air-conditioning market. There are important opportunities for growth, given the abundance of the resource, the proven technology, the inherent environmental advantages and the life-cycle costs.

10.2.7 Tidal

Tidal power plants use the continuously varying head of water associated with the occurrence of tides. Tides are created by the gravitational attraction of the moon and sun acting on the oceans of the rotating earth. The relative motions of these bodies cause the surface of the oceans to be raised and lowered periodically. Tides in the open ocean have a maximum amplitude of about one meter, whereas tides closer to the shore, such as those that occur in estuaries, have substantially higher amplitudes.

The modern tidal energy scheme consists of a barrage, or a dam, that is constructed across an estuary and is equipped with a series of gated sluices to permit entry of water to the basin. Electricity is generated at a tidal plant by large turbines. The simplest and most commonly preferred method of operation is known as ebb generation. During the flood tide, water enters the basin, and is held there until the tide recedes sufficiently to create a suitable head. Water is then released through turbines, thus generating electricity. The release process is sustained until the tide turns and starts to rise, causing the head to fall below the minimum operating point. As the water rises, it once again enters the basin, thus repeating the cycle.

Canada has one demonstration project in Nova Scotia, the Annapolis power station (20 MW), which is built on a causeway. Other sites have been evaluated, including three sites located in the Bay of Fundy. These sites have a combined potential of approximately 7 500 MW of installed capacity, and are the ones most likely to be developed over the next 40 years. Estimates of capital costs (excluding land and transmission) have been made for these sites based on simulations. The low end of the installed capital cost range ($160 per kW) corresponds to the projected costs for Minas Basin, and the high end ($3 500 per kW) corresponds to similar projections for Cumberland Basin.

The results of the economic analysis of tidal energy indicate a supply cost range of $15 to over $44 per gigajoule. At the low end of the range, tidal energy could be cost competitive with the residential and commercial electricity supply generated using conventional fuels. However, practical estimates of construction costs would likely lead to a supply cost much greater than the price of conventional fuels.

The cost of tidal power per kW of installed capacity tends to be very high and site-specific. In addition, while the technology is well developed from a plant and equipment perspective, there is little experience with building large marine structures. The maturity of the tidal technology suggests that future cost/performance improvements will probably be relatively small. In addition, serious environmental concerns associated with the tidal technology exist. These are currently being studied with the support of federal research grants. The primary concerns being addressed are: fish mortality and impact of construction and operation of this type of projects on the environment.

10.2.8 General Comments

The supply costs of renewable energy technologies developed by the Hickling Corporation are compared to the end use conventional energy prices developed in this report. In broad terms, when the supply cost range of a given renewable energy technology is greater than the price of all conventional fuels in the market to which it applies, it is not economically attractive; when the supply cost is less than conventional fuel prices in the particular market, the renewable energy technology may be economically attractive. A situation where the supply cost range straddles the conventional fuel prices requires closer examination of the economic competitiveness of the technology. A summary of the comparison of end use renewable energy supply costs with conventional energy prices is presented in Figure 10-1.

The results of the economic analysis of each renewable energy technology show that some factors impact more on the level and variability of the supply costs of technologies than others. For example, the supply costs for biomass technologies are very sensitive to the portion of operation and maintenance costs pertaining to fuel input. The technologies which are particularly sensitive to conversion efficiencies include wind energy systems (i.e., in terms of average wind speeds), active solar heating and photovoltaic systems (i.e., availability of solar radiation), and small hydro developments (i.e., flow rates, availability and demand). The economics of municipal solid waste facilities are very sensitive to the avoided cost of landfill.

10.3 END USE CONSUMPTION

In 1992, renewable energy sources accounted for about seven percent of Canada's end use energy requirements, while regional contributions were higher, amounting to 18 percent in British Columbia and the Territories. Atlantic provinces closely followed the region of British Columbia and the Territories, with about 13 percent of their 1992 end use demand being met by renewable energy. Other regional contributions

include Quebec at about seven percent, down to about two percent for Alberta (see Table 10-1).

Of the total 489 PJ of energy demand met by renewable energy sources, about 80 percent was wood waste consumed in the pulp and paper and forest industries, 19 percent represented wood consumption in the residential sector, while all of the other sources accounted for under one percent. The wood waste used in the industrial sector accounted for about 16 percent of Canadian industrial energy demand. Renewable energy accounted for about 6.5 percent of the total Canadian residential energy demand (estimated at 1 454 PJ), with wood representing about 93 PJ, or just under 98 percent of the renewable energy contribution.

Measuring the use of renewable energy in the residential and commercial sectors poses certain difficulties. In some instances, wood, wind or solar may be viable alternatives to a primary conventional source of energy. The use of passive solar, or infrequent use of wood, may be measured as conservation (as it reduces requirements for conventional, measured energy sources) rather than as consumption of renewable energy. Thus, it is likely that our estimates understate the use of some of these renewable energy forms,

FIGURE 10-1

Comparison Between End Use Alternative Energy Supply Costs and Conventional Energy Prices

Source: Appendix Tables 10-1 and 10.2
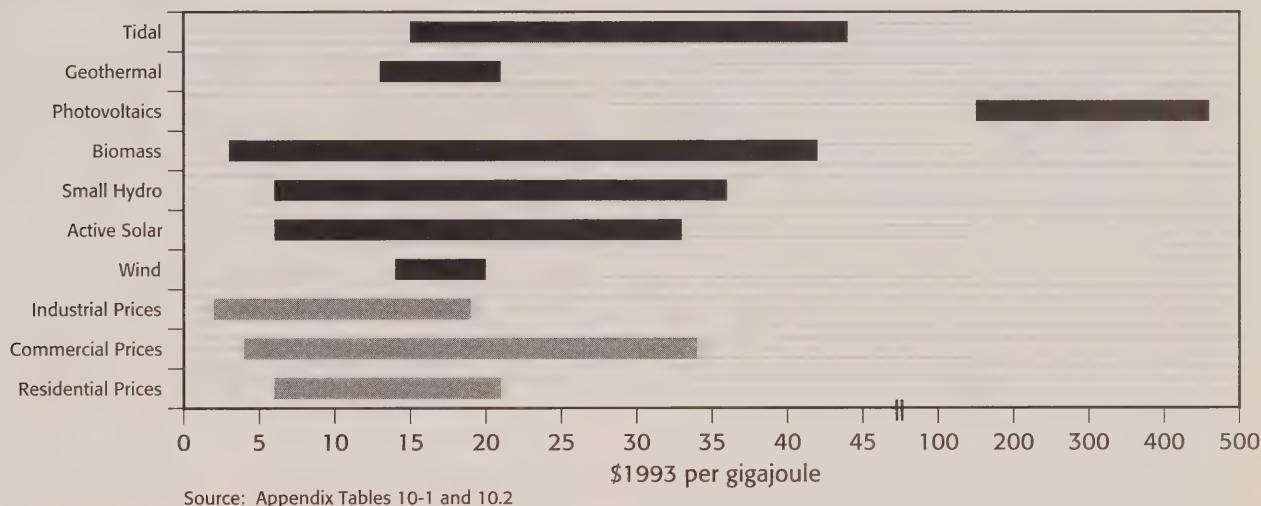
TABLE 10-1

End Use Consumption of Alternative Energy by Region
(PJ/yr)

Region	1992		2010	
	Alternative Energy	Total Energy	Alternative Energy	Total Energy
Atlantic	66	515	76	627
Québec	109	1 520	136	1 935
Ontario	91	2 519	139	3 502
Manitoba	8	232	10	279
Saskatchewan	10	313	11	353
Alberta	30	1 235	43	1 837
British Columbia & Territories	175	989	225	1 339
Total Canada	489	7 323	640	9 872

although we have attempted to account for their impact on the use of conventional energy sources.

Over the projection period, we expect very little change in the share of renewable energy in Canada's total end use demand. By 2010, renewable energy is projected to account for about 6.5 percent of Canada's total end use energy demand, compared to its seven percent share in 1992. However, the shares of individual sources of renewable energy in the total renewable energy consumption are expected to change more notably. The amount of wood waste used in the industrial sector is expected to increase to about 84 percent or 535 PJ of the total 640 PJ of renewable energy consumption. While the wood use in the residential sector is expected to decline to about 15 percent of the total end use consumption of renewable energy.

10.4   ELECTRICITY GENERATION

A locally important part of the demand for electricity is also being supplied by renewable energy. In 1992, renewable energy accounted for about 1.4 percent of Canadian electricity generation. The proportion in certain regions was much higher, reaching about 27 percent of Northwest Territories' electricity generation. Other regional contributions varied from seven percent for Yukon, down to less than 0.5 percent for Quebec, Manitoba and Prince Edward Island. Of the total of 6 917 GWh produced using renewable energy, about 50 percent or 3 450 GWh was supplied by small hydro projects, 49 percent was supplied by biomass, while all other sources accounted for under one percent.

In the Northwest Territories, small hydro accounted for all of the 27 percent contribution made by renewable energy, and the 158 GWh of generated electricity, also accounted for five percent of the total small hydro contribution to Canada's electricity demand. This is an example of the use of renewable energy in a relatively small local market, where the use of a particular energy source is fostered by unique circumstances. The total installed capacity in the Northwest Territories is only about 190 MW (compared to 105 GW of total capacity in Canada), small hydro represents about 30 MW or 16 percent of the total.

The total installed capacity of renewable energy developments in Canada is about 1 700 MW, with small hydro and biomass representing about 800 MW and 900 MW respectively. All other renewable energy sources add up to about 10 MW. By 2010, renewable energy based capacity is projected at about 2 600 MW

(compared to 134 GW of total capacity in Canada), with small hydro and biomass representing over 1 200 MW and over 1 300 MW respectively. Contribution from all other renewable energy sources is projected at about 30 MW, as compared to 10 MW in 1992, with wind energy projects accounting for most of the growth.

Due to the increased renewable energy based capacity, we expect a slight increase in the share of renewable energy in Canada's total electricity generation. By 2010, renewable energy is projected to account for about 1.7 percent of Canada's total electricity generation, up about 0.3 percent from 1992. Biomass is expected to account for about 6 600 GWh, or 56 percent of the 11 860 GWh total contribution of renewable energy; small hydro will account for about 43 percent of the total, down from 1992. The decrease in small hydro's contribution can be attributed to increasing scarcity of economically attractive resource sites, leaving the more expensive projects for future development.

10.5   PRIMARY ENERGY CONSUMPTION

The primary consumption of renewable energy is comprised of end use requirements and fuel required to produce electricity. In 1992, renewable energy accounted for 529 PJ or about six percent of the total Canadian primary energy demand. End use consumption accounted for about 92 percent of primary renewable energy consumption. The other 40 PJ of renewable energy was used to produce electricity.

During the projection period, primary consumption of renewable energy increases by about 35 percent. The use of renewable energy as fuel for electricity production increases by about 83 percent, while end use consumption increases by about 31 percent over the projection period. Nevertheless, by 2010, renewable energy accounts for about five percent of the total Canadian primary energy demand, down from its 1992 contribution.

10.6   CONCLUDING COMMENTS

Renewable energy sources have been successfully developed to provide energy in the markets where they are both abundant and have relatively low supply costs. Our assessment identifies future potential for the use of renewable energy sources, which may be large in several niche markets. These markets, where the renewable energy supply costs may be lower than the conventional energy supply prices, include:

- utilization of passive solar for energy in the building stock;

- active solar water heating in swimming pools;

- active solar industrial air heating/ventilation;

- biomass based electricity and steam generation and/or space heating in commercial and industrial sectors;

- photovoltaic systems in remote telecommunications, lighting, or monitoring devices;

- photovoltaic systems in remote communities for off-grid electricity generation;

- wind powered water pumping systems;

- small hydro projects for on-grid electricity generation.

The main factors influencing the use of renewable energy in specific markets are: availability and efficiency of the renewable energy resources, costs of their development and implementation, cost of competing fuels, differences in environmental impacts of conventional and renewable energy, awareness of the general public and industry regarding renewable energy, and government policy related to the development and use of renewable energy sources.

These factors can have both positive and negative effects on the future of the renewable energy industry. Important considerations for renewable energy use include: generally positive environmental impacts, sustainable fuel supplies, integrated resource planning, converging costs of renewable and conventional energy supply, and niche markets where costs of conventional energy are higher than those of renewable energy. However, there are also important barriers associated with the development of the industry, such as land use requirements, high initial capital costs, small and fragmented industry, procedures for environmental assessment and licensing, and the intermittent nature of the energy supplied from several of the renewable sources.

The contribution of renewable energy sources to the overall supply of energy in Canada is not expected to change notably over the next 20 years. However, their utilization could be strongly influenced by moves towards sustainable development, or the implementation of stringent emission levels. We have observed large supply cost reductions for renewable energy sources as their technologies have advanced and we recognize that future development and cost reductions will require sustained additional research and development.

The supply costs of conventional energy and renewable energy do not include the costs of externalities such as environmental impacts, waste disposal, decommissioning and human risk. It has been suggested that these costs are relatively small for renewable energy sources in comparison to conventional energy sources. Some jurisdictions have already or are currently reviewing issues relating to the use of renewable energy; for example, British Columbia is implementing a social costing methodology that will rank all future energy projects on their total financial, environmental and social costs. In 1991, Ontario Hydro released a paper entitled "Alternative Energy Review". The review was used to assesses six alternative electricity generation technologies which offer the greatest potential for application in Ontario by the year 2014. It is worth noting that if environmental and other externalities were reflected in total energy costs for all sources of energy, some estimates suggest that the overall contribution of renewable energy could more than triple in the next 20 years.

Chapter 11

IMPLICATIONS OF ENERGY PROJECTIONS FOR ATMOSPHERIC EMISSIONS

The production and use of energy, primarily fossil fuels, is the largest source of atmospheric pollution arising from human activities. The purpose of this chapter is to describe the emissions which arise as a consequence of energy production and consumption in Canada. Emission amounts are related to fuel type and combustion technology used and the emission projections are directly linked to our energy projections. The five gases examined are among the leading atmospheric pollutants emanating from the energy sector.

The emissions considered in this report have global, regional and local impacts. A major concern on a global scale includes the greenhouse gases (GHGs), principally carbon dioxide (CO_2) and methane (CH_4), which contribute to climate warming. Of importance on the regional scale, are the acid forming gases – sulphur dioxide (SO_2) and the oxides of nitrogen (NO_X), which contribute to the formation of acid rain. At the local level, urban smog and ozone in the lower atmosphere are a concern and the ozone precursors, the volatile organic compounds (VOCs) and NO_X are therefore considered. This chapter will outline the key environmental issues to which these emissions give rise, describe the techniques used to calculate emissions and provide projections of the total gaseous emissions.

11.1   EMISSION UNCERTAINTIES

There is a wide range of uncertainty associated with any estimates of future atmospheric emissions. Estimates, including those presented in this report, are highly dependent on a number of assumptions. Differences between our emission projections and those of other agencies reflect differences in assumptions made on economic growth, attendant energy usage in each sector, fuel mixes, the relative importance of thermal plants in electric power generation and other factors.

Emissions will also be influenced by the direction of environmental policy in Canada and abroad, as well as changes in technology. It is recognized that environmental standards and control technologies will change during the projection period. However, the nature and magnitude of these changes is still evolving

and we have not speculated on policy direction or the magnitude of technological improvements that may reduce emissions. Therefore, our analysis represents a *status quo* approach to the projection of emissions, in that we assume that the current policy framework and the technology used to control emissions remains unchanged. An implication of this approach is that actual future emissions may be lower than our projections.

11.2   CONSULTATION FINDINGS

During May 1993, consultations were held with interested parties from over sixty industry, government and other organizations across Canada to solicit views about the direction for our 1994 Supply and Demand Report. The feedback was that an examination of the environmental implications of the projections was important and should be done. Some of those consulted felt that more emphasis should be given to impacts on the ecosystem and that the analysis should be formulated in a sustainable development framework. Many were interested in our view of how the energy industry was performing relative to present and developing standards. Weighing all these views, it was decided that the treatment afforded the topic in the 1991 Supply and Demand Report was appropriate and should be expanded to include more recent information on emissions.

Additional technical consultations were held with industry and various federal and provincial government departments and agencies. Some of these organizations have completed their own detailed inventories of gaseous emissions. In our analysis we have ensured that the emission calculation techniques we use are consistent with published approaches.

11.3   ENERGY-RELATED EMISSIONS

Our analysis develops an estimate of atmospheric emissions for the base year of 1992, and uses a consistent accounting methodology to project these emissions to 2010 based on our assumptions on energy pricing and economic growth.

Atmospheric emissions of six key gases produced in 1990 by the energy sector are compared with non-energy emissions in Figure 11-1. In Canada, CO_2 is by

far the most abundant gas with over 500 megatonnes produced of which approximately 90 percent arise from the energy sector. For each of the other gases, total Canadian emissions are over two orders of magnitude smaller. Energy related sources account for approximately 35 percent of total CH_4, 90 percent of NO_X, 55 percent of VOCs and 45 percent of SO_2 emissions. Nitrous oxide (N_2O) a potent greenhouse gas is emitted in relatively small quantities and estimates of the total quantity of emissions of this gas vary widely. Overall, in 1990, energy-related emissions constituted about 50 percent of the total emissions. Since N_2O emission factors have not been estimated with an acceptable degree of certainty for the range of combustion technologies examined in our report, we did not examine emissions of this gas.

To calculate total emissions, there is some degree of subjectivity as to which sources to include in the energy sector. For this report, we have calculated emissions arising from direct combustion of fossil fuels (such as gasoline, fuel oils and natural gas) in the key sectors of the Canadian economy (transportation, residential, commercial and industrial). Emissions arising from transforming energy from one form to another (e.g., coal and natural gas to electricity, crude oil to refined products) are also included. Also ascribed to the energy sector are fugitive emissions which arise during the production and transportation of primary fuels, emissions of CH_4 from coal beds, CO_2 from gas reservoirs, releases from fuel storage and from the transportation of refined oil products. Emissions resulting from energy consumption, production and processing are directly linked to our primary energy demand projections.

11.4 EMISSIONS CALCULATION METHODOLOGY

Emissions calculations are provided for each of the Current Tech, the High Tech and the Enhanced Cooperation cases. A comparison of the three cases gives insight into the impact on the environment of changes in the fuel mix of energy production and consumption. The High Tech case envisions a scenario in which new technology increases the availability of natural gas and decreases its price relative to other fuels. The Enhanced Cooperation case examines the implications of the development of large-scale hydroelectric projects to serve regional loads if electric power generation planning were done on a regional rather than a provincial basis. This case was constructed as an extension of the Current Tech Case and only affects emissions resulting from the electric power sector. In the High Tech and Enhanced Cooperation cases, emissions of many gases are reduced from levels observed in the Current Tech Case.

FIGURE 11-1

Gaseous Emissions from Human Activity in Canada 1990

(million tonnes)
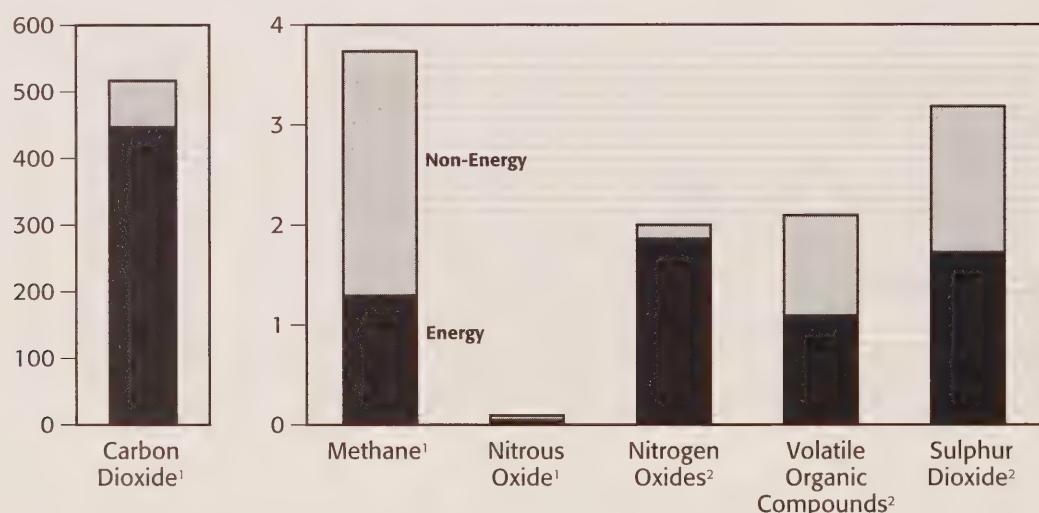
1 Source: Canada's Greenhouse Gas Emissions: Estimates for 1990, A.P. Jaques, Environment Canada Report EPS 5/AP/4, December 1992.
2 Source: Preliminary Emissions for 1990, L. Greenwood, Environment Canada, May 1994.

Our approach to estimating emissions for combustion uses is based on the application of emission factors to fuel type and combustion technology. To ensure consistency with other Canadian inventories, we have used factors published by Environment Canada (EC) and Natural Resources Canada (NRCan). These are listed in Table A11-1 of the Appendix. To calculate emissions arising from the upstream oil and gas sector, we used emission survey results prepared for the Canadian Association of Petroleum Producers (CAPP) and Environment Canada[1]. From these surveys, emission factors were calculated and used in scenario projections.

For the electric power industry, emissions were calculated for major Canadian utilities but not for independent power producers. Emission factors for each thermal plant were developed for all gases from a review of in-house and existing published data. This was followed by a review of the factors by the Canadian utilities and, finally, based on the utilities' responses and further internal review, final emission factors were developed. Our estimates of SO_2 emissions incorporate the emission control plans proposed for implementation by the utilities through the period of the projection. It is assumed that no emissions arise from the nuclear energy or the hydroelectric generation sectors in Canada. In the latter case, it has been speculated that the decay of vegetation in hydro reservoirs may be a source of CO_2 and CH_4. However, research is still at a preliminary stage and as emission factors are not yet agreed upon, it is premature to consider this potential source of greenhouse gases.

Emissions from the upstream natural gas industry as well as those emissions from bitumen production and upgrading which are not accounted for in primary industrial demand are calculated in detail. Emissions from the natural gas sector result from fuel combustion associated with production and processing. Sources of emissions related to oil sands activity include: natural gas use for steam generation at in-situ bitumen recovery projects; the combustion of process gas and natural gas in oil sands plants; the use of by-product coke as fuel at oil sands plants; the burning of natural gas and other materials to generate electricity for the oil sands plants; and the use of feedstock gas (for conversion of natural gas to hydrogen) in bitumen upgrading.

The Alberta Energy Resources Conservation Board (ERCB) assisted by calculating emissions from combustion sources in the upstream oil and gas and the oil sands industries in Alberta. The models developed by ERCB were considered to be the most appropriate for projecting upstream emissions and have been used extensively to develop provincial emissions projections. The ERCB models were run using our energy projections for Alberta as input to compute emissions for the upstream industry in Alberta. Using the Alberta estimates, and assuming that technological practice was similar in other producing provinces, we projected emissions for oil and gas production for the rest of Canada.

Some portion of Canada's energy resources are exported, and concerns arise as to whether emissions from the production and transportation of these resources should be ascribed to a Canadian emissions inventory. We have not attempted to isolate these quantities and subtract them from the Canadian domestic projections. Similarly, although some portion of Canada's fossil fuel requirement is imported, we do not calculate emissions from the production of such fuels outside Canada's borders.

To calculate emissions from road transportation, emission rates are specified in grams of NO_X and VOC emitted per unit of distance driven. These emissions are a function of emission standards for each model year, the projected vehicle stock inventory and distance driven by each category of vehicles. The vehicle inventory dates back 25 years and forward to the end of the projection period in five year increments. The standards used for vehicle emissions are more stringent for cars and trucks in coming years. Vehicles built prior to 1985 are assumed to have emission rates equal to the 1985 standard. Further advances beyond existing legislated standards are not included, although with the retirement of older vehicles, a decline in NO_X and VOC emissions occurs. A listing of current and projected rates used in the transportation sector are provided in Appendix Tables A11-2 to A11-5.

11.5 ATMOSPHERIC EMISSIONS

11.5.1 Greenhouse Gases

Over the past decade, the potential for climate warming which may result from the atmospheric greenhouse effect has gained a high level of public attention. The greenhouse effect in the earth's

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1 The report, *A Detailed Inventory of CH_4 and VOC Emissions From Upstream Oil and Gas Operations in Alberta*, by D. J. Picard, B.D. Ross and D. W. H. Koon, was prepared for the Canadian Association of Petroleum Producers. This work was later expanded by Environment Canada to encompass the upstream oil and gas industry across Canada.

atmosphere is a natural phenomenon which is enhanced by certain gases. The process is illustrated schematically in Figure 11-2. The mixture of gases in the atmosphere acts as a blanket through which solar energy is readily transmitted to the earth's surface where it is absorbed. Energy is in turn re-emitted from the earth in the form of long wave or infra-red radiation. The atmosphere is not transparent to this re-emitted energy and as a result a portion of the energy is absorbed, heating the atmospheric gases.

This radiative energy transfer is to a large extent in balance, maintaining a mean global temperature which varies only a few tenths of a Celsius degree from year to year. It has been estimated that were it not for this greenhouse property of the atmosphere, the mean atmospheric temperature would be some 33 Celsius degrees colder than at present – much colder than that required to sustain present life forms on the earth's surface. The generally accepted hypothesis is that as

atmospheric concentrations of the GHGs increase, so too will the average atmospheric temperature.

Although the magnitude and impacts of this warming are not completely understood, there is widespread concern among scientists that the overall impact may be negative on the earth's ecosystem. This is the conclusion reached by the International Panel on Climate Change in its 1990 analysis[2]. The scientific consensus and the developing awareness of the problem by world political leaders has led to the development of a set of international accords focussing on the control of GHGs originating from human activity. The result is the Framework Convention on Climate Change (FCCC) which was signed by over 150 countries in 1992. Canada supports the FCCC and ratified the Convention in

2 Source: Houghton, J. T., G. J. Jenkins and J. F. Ephraums (eds.): Climate Change: The IPCC Scientific Assessment, Cambridge University Press, Bracknell, U. K. (1990)

FIGURE 11-2

The Greenhouse Effect – A Simplified Illustration[1]

Most radiation is absorbed by the earth's surface and warms it.

EARTH

Infra-red radiation is emitted from the earth's surface.
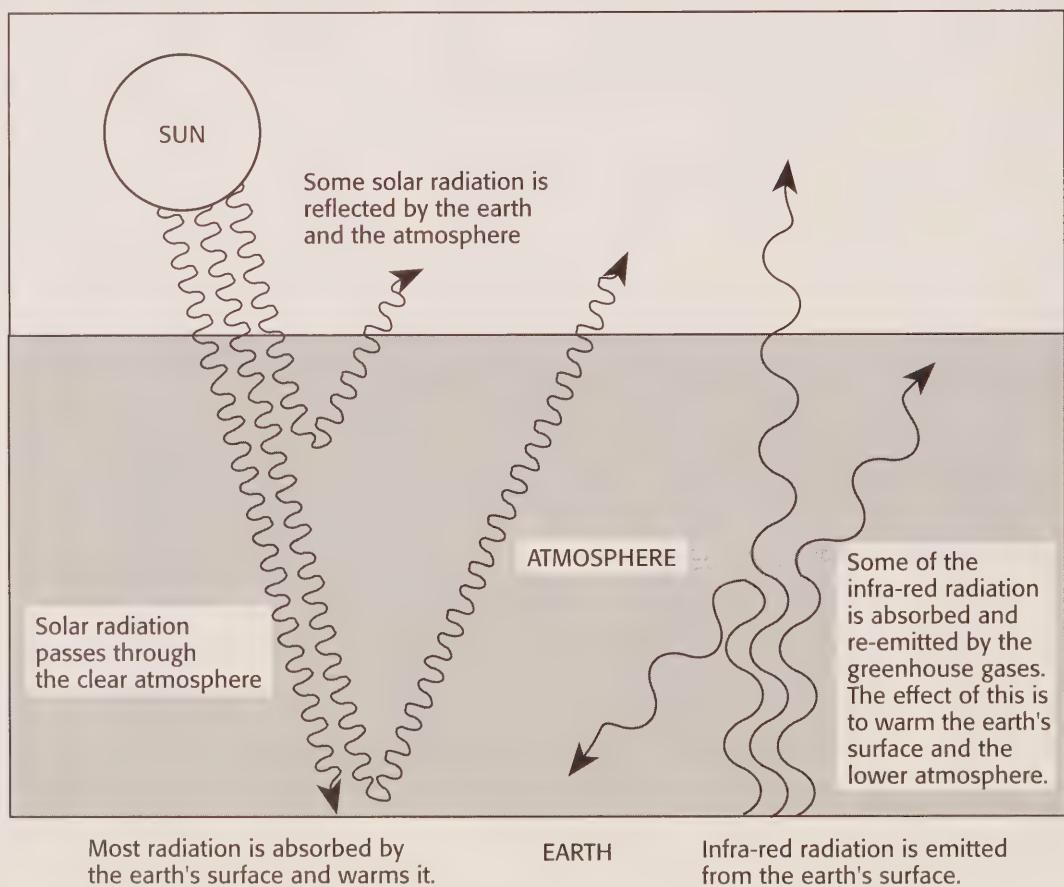
1 Adapted from Houghton et al (1990) op. cit.

December 1992. Upon ratification by 50 countries, the FCCC came into force in March 1994. Although the FCCC sets no legally binding targets, countries are encouraged to examine a range of policy options. Canada has set a stabilization goal which is to return our GHG emissions to their 1990 levels by the year 2000. At the present time a number of measures have been proposed in Canada but as yet none has been accepted. In our projections, we therefore do not presume any measures to control GHGs in Canada.

The primary greenhouse gases produced by the energy sector are CO_2, CH_4 and N_2O. Canada, which contributes about 2 percent of the world total of CO_2, is the eleventh largest CO_2 producer in the world, and the third largest on a per capita basis. The proportion of CH_4 and N_2O attributable to the energy sector is smaller and the absolute magnitudes of emissions of these gases are dwarfed by those of CO_2. While other gases such chlorinated fluorocarbons (CFCs), methyl chloroform and carbon tetrachloride are important GHGs, they are not emitted from the production, processing, transportation or burning of fossil fuels. Therefore they are not quantified in this report.

Different greenhouse gases play different roles in enhancing the greenhouse effect. Many have a much stronger impact than CO_2 on a molecule by molecule basis. Other gases can be compared to CO_2 using the Global Warming Potential (GWP), which quantifies the radiative effect of the instantaneous release of a gas relative to release of the same amount of CO_2. Because the different greenhouse gases survive for various time periods in the atmosphere, their effects are summed over a specified period of time. In Table 11-1, an example of the contribution of these gases to global warming is shown. Carbon dioxide accounts for 61 percent of the global warming potential while CH_4 contributes 15 percent of the total warming potential even though the quantity of emissions are 100 times smaller than CO_2 emissions over the globe. CFC emissions are very small yet they contribute significantly to the global warming effect.

For our base year of 1992, emissions of CO_2 in Canada totalled 458 megatonnes (Mt). This excludes an additional 47 Mt released from the combustion of biomass fuels (wood and wood byproducts).[3] As shown in Figure 11-3, the transportation sector is the largest

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3   By convention, CO_2 emissions due to biomass are not included if a nation's forests are managed in a sustainable manner. In Canada, forests are a slight net sink for carbon and sequester slightly more CO_2 per year than is emitted through combustion of wood.

TABLE 11-1

The Greenhouse Gases – Proportional Contributions to the Greenhouse Effect[1]

	CO_2	CH_4	N_2O	CFCs	Others
Lifetime in Atmosphere (yrs)	40-150	11	132	55-550	days – 80
Global Emissions (Mt/yr)	26,000	300	6	1	300
GWP[1] (100 year)	1	11	270	3400-7000	50-5000+
Proportion of total effect	61%	15%	4%	11%	9%

1   Source Houghton et al (1990), op. cit. p xxi. The proportion incorporates both the direct and indirect effects of these gases. Direct effects reflect the importance of the gas itself in the greenhouse warming process. Indirect effects arise for those gases such as CH_4 which participate in reactions in the atmosphere resulting in increases in concentration of other greenhouse gases (both CO_2 and ozone). The net indirect effect for methane is positive.

# FIGURE 11-3
Energy Related Carbon Dioxide Emissions – 1992

Total Emissions 458 Mt
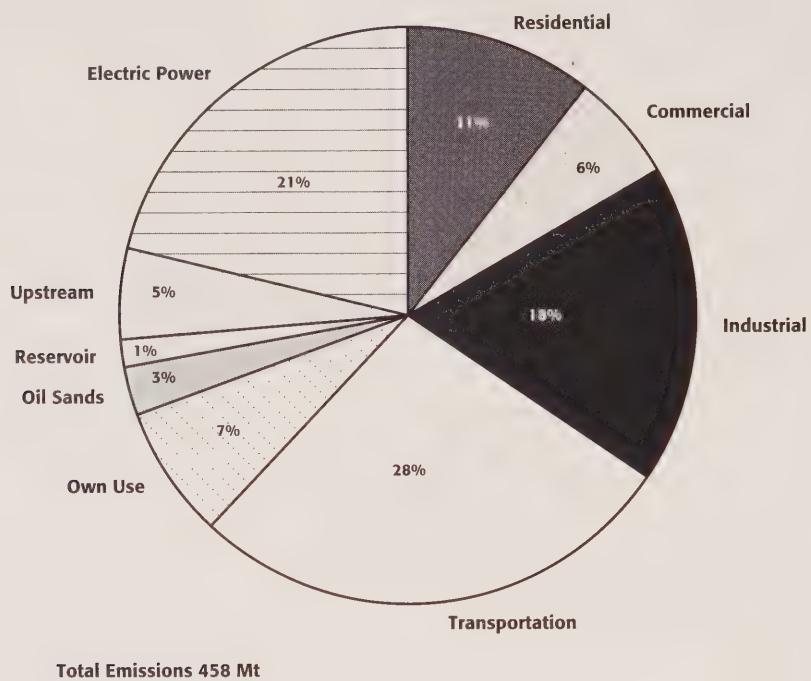
FIGURE 11-4
Energy Related Methane Emissions – 1992

Total Emissions 1473 kt

CANADIAN ENERGY SUPPLY AND DEMAND 1993 – 2010
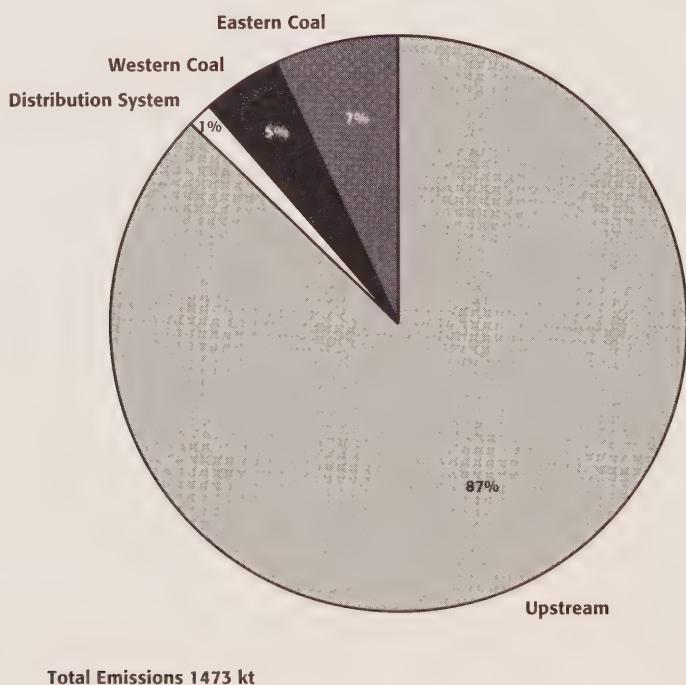
single source at 126 Mt. Stationary sources in the industrial sector emitted 82 Mt of CO_2, the electric power industry 97 Mt, residential sources 48 Mt and commercial sources 28 Mt. The upstream oil and gas sector emitted 23 Mt and reservoir CO_2 amounted to 7 Mt. Other emissions including those from oil sands plants and refineries, totalled 47 Mt.

Total emissions of energy-related CH_4 in 1992 were 1,473 kilotonnes (kt). The distribution of emissions among the various sectors is shown in Figure 11-4. The largest proportion, at 1 285 kt, was emitted in the upstream oil and gas sector. We estimate that in this sector, the natural gas production industry emitted 528 kt, the conventional oil sector 145 kt , the heavy oil sector 331 kt, in-situ crude bitumen 23 kt, and gas transmission within the upstream industry about 166 kt. Other sources amounted to 93 kt. Emissions from the downstream natural gas transportation system amounted to 21 kt. The inventory does not include the small amount of emissions due to fuel combustion, which constituted less than one percent of total CH_4 emissions in 1990 according to Environment Canada[4].

The mining of coal in Canada results in a substantial amount of CH_4 released to the atmosphere.

Since coal found at greater depths and therefore at greater pressure generally contains more CH_4, fugitive CH_4 emissions from underground mines are much greater than from surface mines on a per tonne of coal mined basis. For this reason, the shallow coal deposits of western Canada contain and release less CH_4 than the deeper deposits found in Atlantic Canada. Methane collected by ventilation and drainage in underground mines is generally vented to the atmosphere.

With surface mines, CH_4 is released from the overlying rock as well as the coal itself as it is mined. It has been assumed by Environment Canada that the amount of CH_4 released from overburden is approximately three times that released per tonne of coal mined. We estimated that in 1992, emissions from western Canadian coal mines was 66 kt and from eastern Canadian coal mines 102 kt.

11.5.2 Acid Forming Gases

Acid rain has been a concern for over two decades in Europe, and almost as long in North America. Acidic precipitation is formed when acid gases such as SO_2 and

4   Source: *Canada's Greenhouse Gas Emissions: Estimates for 1990*, A. P. Jaques, Environment Canada, Report EPS 5/AP/4, December 1992

FIGURE 11-5
Energy Related Sulphur Dioxide Emissions – 1992

Oil Sands

Solution Gas Flare
5%

Coal Fired Utility   51%

Sulphur Gas Processing
23%

7%

Oil Fired Utility

Total Emissions 1242 kt
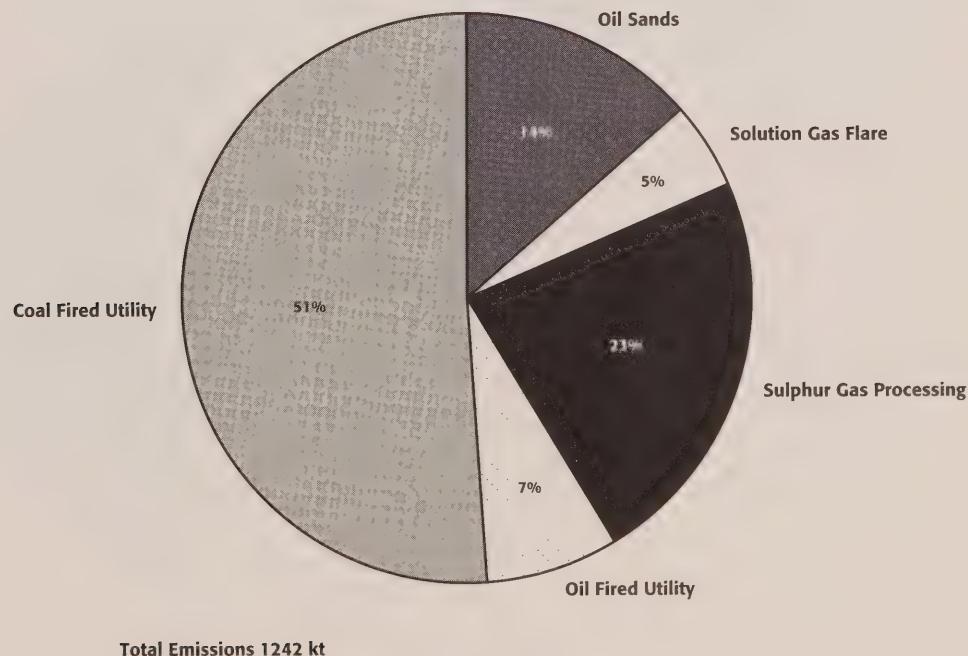
NO$_X$ react with water vapour to form sulphuric acid and nitric acid respectively. Direct deposition of dry particulates and adsorption of gases on vegetation, land and water surfaces also occurs and these may subsequently be converted to acids as the result of interaction with water.

Control of emissions of SO$_2$ and NO$_X$ is the focus of the Canada – USA Air Quality Agreement signed in 1991. In addition, a set of federal-provincial agreements limiting SO$_2$ emissions have been in force for a number of years. These agreements impose limits on permitted tonnage of emissions for Canada and commit several provinces to implement pollution control technologies. For SO$_2$, the agreement specifies that by the year 2000, total Canadian emissions will be limited to 3.2 million tonnes per year and to 2.3 million tonnes per year for the seven provinces east of Saskatchewan. Within the provincial agreements, maximum SO$_2$ emission caps for the utility sector are specified.

Our inventory includes SO$_2$ emissions from electricity production and the regulated caps are explicitly included in our estimates. Emissions from upstream oil and gas production are also included but we do not quantify the emissions arising from the industrial (e.g., smelters), transportation, or agricultural sectors (e.g., fertilizer application).

For the natural gas industry, SO$_2$ emissions are determined primarily by the production levels and sulphur content of natural gas and the level of sulphur recovery during processing. Natural gas plants that process sour gas emit a small amount of SO$_2$ as part of the sulphur recovery process. Flaring of sour gas at processing plants and well testing also contribute to SO$_2$ emissions. For bitumen production and upgrading, SO$_2$ emissions are largely determined by the processing techniques used. Sulphur is recovered from natural gas plants at a rate of about 98 percent. At oil sands and in-situ bitumen plants, recovery is approximately 88 percent. There is no sulphur recovery from testing of sour gas wells or solution gas flaring.

Sulphur dioxide emissions attributable to the energy sector amounted to 1 242 kt in 1992. As shown in Figure 11-5, over half of this total, or 634 kt was due to emissions from coal-fired utilities. Oil-fired plants emitted 94 kt of SO$_2$. Natural gas-fired plants emitted less than 0.1 kt of SO$_2$. In our calculations, emissions are based on the average sulphur content of the coal and heavy oil used in different regions of the country.

Sulphur dioxide emissions in the oil and gas sector totalled 514 kt in 1992, of which the oil sands plants in Alberta generated 168 kt. The natural gas sector emitted 284 kt of which the largest amount (212 kt) was from

FIGURE 11-6
Energy Related Nitrogen Oxide Emissions – 1992

Total Emissions 1851 kt
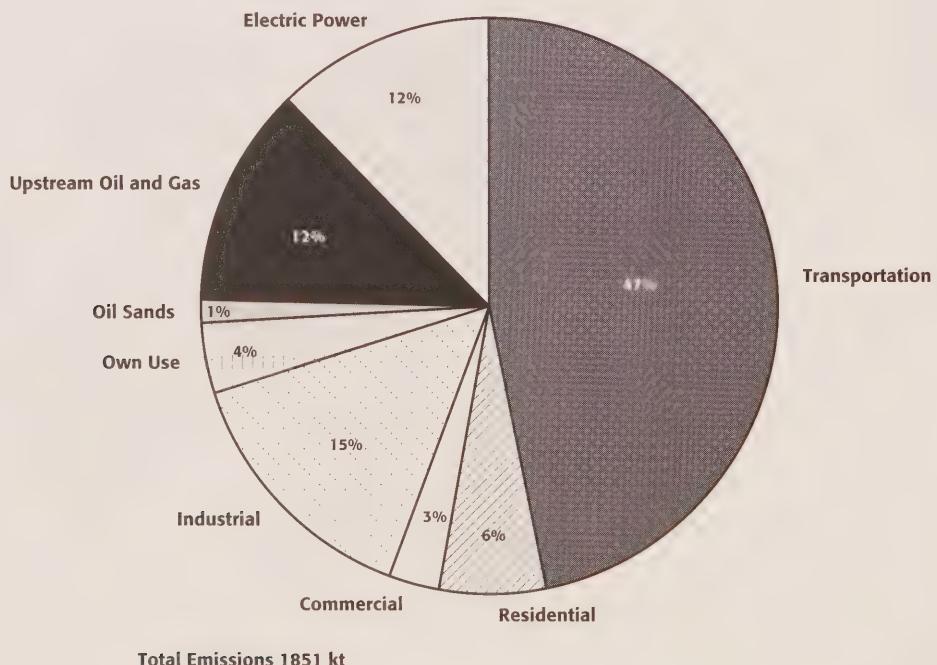
sulphur recovery plants, with smaller amounts from acid gas flaring (41 kt) and sour gas well battery testing (31 kt). Solution gas flaring from conventional light crude production in Canada was estimated at 62 kt.

Canadian energy related emissions of NO_X were calculated from primary energy demand, the upstream oil and gas industry and the electric power industry. In 1992, these emissions totalled 1 851 kt. As shown in Figure 11-6, almost one half of these emissions, (877 kt), arise from gasoline and diesel engines used in transportation. Of the 230 kt emitted in the electric power sector, most (182 kt) were from coal fired plants. In the oil and gas sector, where 234 kt was emitted, the largest fraction (192 kt) was attributable to the natural gas processing industry, and lesser amounts to oil sands plants (23 kt) and to oil production facilities (15 kt).

11.5.3   Volatile Organic Compounds and Ozone

Ozone in the lower atmosphere is formed as a result of a complex chain of reactions between NO_X and VOCs in industrial and urban areas. The three areas in Canada where low-level ozone is considered a chronic problem are the lower British Columbia mainland, the Windsor-Quebec City corridor, and in the area around the Bay of

Fundy. Ozone is a key ingredient in urban smog and has serious detrimental effects on life forms. It can impede respiratory function, negatively affect human health in other ways and can adversely affect crop productivity[5]. Although some of the VOCs which lead to formation of ozone occur naturally (e.g., terpene emissions from forested areas), human originating sources are most important. The VOCs included in this report are the photochemically reactive hydrocarbons such as the alkanes, alkenes, aromatics and ketones. The VOCs specifically exclude CH_4, ethane and the chlorinated organics.

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5   It should be noted that the upper atmosphere ozone issue is separate from the smog issues. The ozone in the upper atmosphere acts as an absorber of solar ultraviolet radiation. It is therefore of primary importance as a protective shield against incoming ultraviolet radiation but it also plays a role in the greenhouse process. Since ultraviolet radiation is known to cause skin cancer, reduce crop yields and have other impacts on the ecosystem, depletion of upper atmospheric ozone is a major concern. Compounds which contribute to ozone depletion are the subject of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. With the exception of NO_X released directly into the stratosphere from jet aircraft, the ozone depleting gases are not a product of the energy sector and therefore are not covered in this report.

FIGURE 11-7
Energy Related VOC Emissions – 1992

Total Emissions 1436 kt
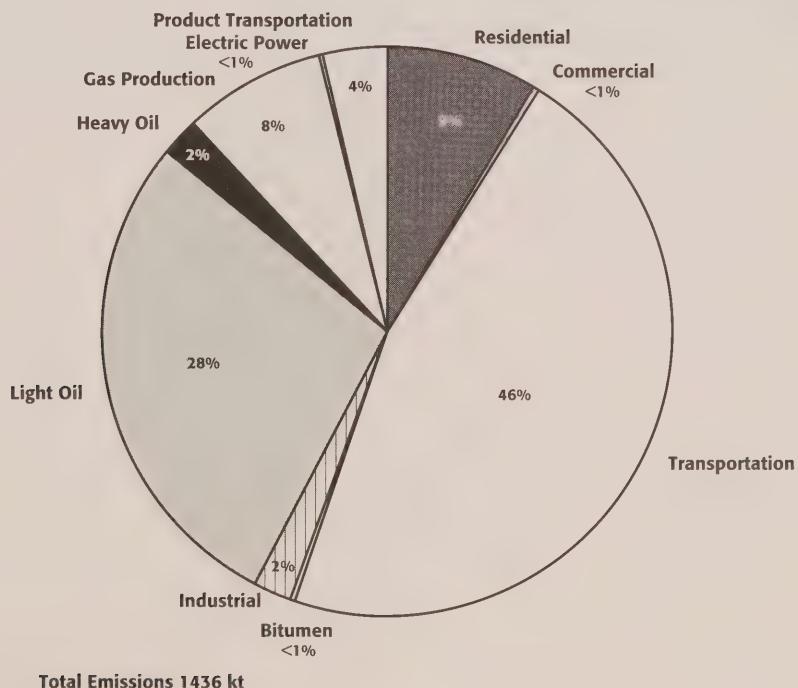
Over the past few years, a commitment has been made by Canada to develop a strategy to control the production of ozone in the lower atmosphere. The plan, approved by the Canadian Council of Ministers of the Environment[6] proposes many initiatives to specifically reduce NO_X and VOC emissions. Approved transportation sector emissions standards for new vehicles are incorporated in our projections.

In 1992, energy-related VOC emissions were estimated to be 1 436 kt. The sectoral distribution is shown in Figure 11-7. The largest proportion were from the transportation sector (667 kt) while stationary sources in the residential, commercial, industrial and electric power facilities contributed a total of 162 kt. In the oil and gas sector, sources include conventional oil production (406 kt), natural gas production processes (116 kt), heavy oil production (31 kt) and a variety of other sources (53 kt) including product transportation and bitumen production.

11.6   EMISSION PROJECTIONS

11.6.1   Current Tech Case

The emissions computed in our projection are directly linked to energy production, the patterns of energy end use consumption and the mix of fuels used. Since combustion of each fuel yields different amounts of emissions, the mix of fuels projected to meet energy demand influences the final emissions total. Figure 11-8 shows a plot of annual emissions of the five gases over the period of the projection. The annual emission for this case are tabulated in Table A11-2 in the Appendix.

Greenhouse Gases

We project a steady increase in CO_2 emissions through the period 1992 to 2010. By the year 2000, the annual rate is projected to rise to 547 Mt and by the end of the period to 652 Mt. This represents an annual average growth rate of 2.2 percent per year during the 1990's and 1.8 percent per year during 2000 to 2010. This growth is dominated by the increased CO_2 produced in the electric power sector, where annual CO_2 emissions increase by 3.7 percent per year to 162 Mt by 2010. Transportation emissions increase by 1.4 percent per year and industrial emission rates by 1.6 percent per year.

Methane shows the most rapid rate of increase of all gases in the early part of the projection period, rising at a rate of 3.4 percent per year to 2000. This growth is

6   *Management Plan for Nitrogen Oxides and Volatile Organic Compounds*, CCME Report EPC/TRE-31E, November 1990.

FIGURE 11-8
Energy Related Emission Projections for Current Tech Case
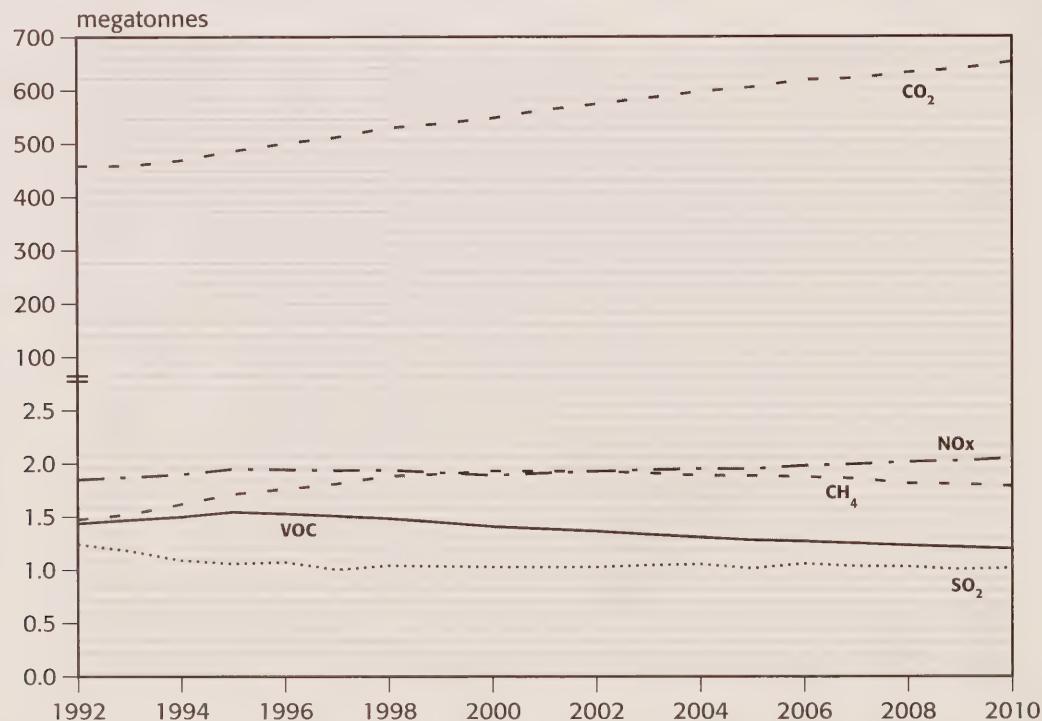
dominated by increases in the upstream oil and gas sector and fugitive emissions from coal mining. Emissions in the oil and gas sector are dominated by natural gas production which grows steadily to the year 2000. As production of crude petroleum and natural gas levels off and starts dropping in the second half of the next decade, coal consumption in the utility sector takes on greater importance than in the 1990s. Consequently, fugitive emissions of CH_4 from coal mining play a proportionately larger role than in the early part of the projection. In the mid-1990s, coal related CH_4 emissions constitute 5 percent of total CH_4 emissions. By the year 2010, emissions of 267 kt constitute 15 percent of the total CH_4 released.

Acid Forming Gases

Emissions from electric power utilities reflect the regulated limits established for sulphur and annual SO_2 emissions from utilities decrease from 728 kt in 1992 to 500 kt by 1995. Annual emissions then fluctuate from year to year between 500 and 600 kt reflecting assumptions made about fuel types associated with new generating facilities, installation of sulphur scrubbing technology and the mix of high and low sulphur coals burned across Canada. Annual emissions of SO_2 from the oil and gas sector are projected to increase steadily to 561 kt by 1996. Thereafter, they are projected to drop to a level which varies from 455 kt to 486 kt between 2000 and 2010 reflecting a combination of decreased emissions from oil production and fluctuations in emissions from the natural gas industry.

NO_X emissions rise at the beginning of the projection period, decrease slowly to the end of the century and then increase steadily, at an annual average rate of 0.8 percent per year through the remainder of the projection period. This pattern is strongly influenced by developments in the transportation sector. As tightened emissions standards for vehicle emissions come into effect and older vehicles are retired, emissions decline steadily from a peak of 916 kt in 1995 to 683 kt by 2005. Thereafter, assuming that no new emission standards come into effect, emissions start to rise reflecting our assumptions about growth in the transportation sector.

After the turn of the century, NO_X emissions are projected to be strongly influenced by growth in the industrial sector where emissions increase from 335 kt in 2000 to 400 kt by 2010. A steady but slow rate of growth of emissions is projected from electric power while emissions from the upstream oil and gas sector are likely to remain nearly constant after the turn of the century.

Volatile Organic Compounds

Energy-related emissions of VOCs are projected to decrease by 19 percent over the study period although they rise through the first three years of the projection. The transportation sector VOC emission trends follow the NO_X trends described above, rising to 691 kt in 1995, then steadily decreasing to 534 kt by 2005, increasing slowly thereafter for the same reasons.

VOC emissions in the upstream oil and gas sector increase to 689 kt in 1996 then follow a steady decline to 471 kt by the year 2010. These trends follow the decreases in conventional oil production throughout the period, as VOC emissions are not dominated by natural gas production.

FIGURE 11-9

Percentage Difference Between High Tech Case and Current Tech Case
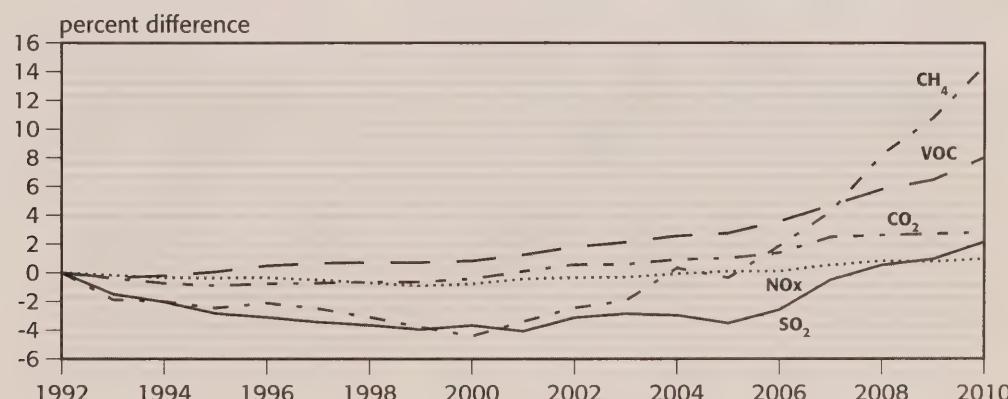
11.6.2 High Tech Case

In the High Tech case, annual emission rates by the end of the projection period are higher than in the Current Tech case for all gases since fossil fuel demand is about 8 percent higher than in the Current Tech case by the year 2010. Annual gaseous emissions for the High Tech case are tabulated in Table A11-3 in the Appendix. In Figure 11-9 the emission rates for the High Tech and the Current Tech cases are compared. In the High Tech case, natural gas is a favoured fuel due to its lower price and increased availability relative to the Current Tech case, and lower combustion related emissions than other fossil fuels. Emissions which arise from the production, processing and distribution of natural gas show the greatest increases over the Current Tech case.

Greenhouse Gases

Carbon dioxide emissions are very similar in both the High and Current Tech cases through 2005 then rise to 2.8% above the Current Tech case to a level of 671 Mt by the year 2010. Emissions from the upstream oil and gas sector are substantially lower in 2000 than in the Current Tech case in keeping with reduced consumption of all fuels. By the end of the period, this relativity reverses and the oil and gas sector contributes significantly more to emissions in the High Tech case. Emissions from the industrial sector show similar reversals by mid-period reflecting the increased availability and dominance of natural gas as a fuel. On the other hand, emissions from the major utilities are slightly higher (0.5 Mt) in the High Tech case by 2000 than in the Current Tech case. By 2010, utility emissions in the High Tech case are 1.8 Mt lower reflecting our assumption that natural gas is substituted for coal.

For CH_4, the effect is much more dramatic and strongly influenced by the upstream oil and gas sector. In the High Tech case, the overall CH_4 emissions are 4 percent lower in the year 2000 and 5.5 percent lower for the upstream oil and gas sector. By the end of the projection period, overall CH_4 emissions are 14 percent higher, driven by 19.7 percent higher upstream oil and gas sector emissions. Methane emissions from coal mines are projected to be 15 percent lower in the High Tech case reflecting the switching from coal to natural gas by electric utilities – consistent with the trend observed in CO_2 emissions from the major utilities.

Acid Forming Gases

With respect to SO_2 emissions, lower natural gas production in the High Tech case at the end of the 1990s results in substantially reduced SO_2 emissions relative to the Current Tech case reflecting reduced production of sour oil and gas. By 2010, as production of gas increases and more sour gas is processed, SO_2 emissions from the upstream oil and gas sector increase by 9.6 percent over the Current Tech case. For the electric utilities, SO_2 emissions in the High Tech case are comparable through mid period and slightly lower by 2010 compared with the Current Tech case. Emissions drop from a relative peak of 595 kt in 2004 to 524 kt in 2010 reflecting a reduction in use of high sulphur fuels by the major utilities.

Total emissions of NO_X differ by less than one percent between the two cases as the small differences in the various sectors for the most part tend to offset one another.

Volatile Organic Compounds

Volatile organic compounds are emitted at a greater rate in the High Tech case through most of the projection period. VOC emissions are not as strongly influenced by natural gas production as are CH_4 emissions and therefore the emissions from the upstream oil and gas sector differ by less than one percent at the end of the century when the mix of fuels is not significantly different than at present. By the end of the projection period however, upstream VOC emissions from heavy and conventional oil are significantly reduced in the High Tech case and upstream emissions from the natural gas industry increasingly dominate.

11.6.3 Enhanced Cooperation Case

The Enhanced Cooperation case assumes that electric power generation planning is done on a regional rather than a provincial basis. Because there is currently a large amount of surplus generating capacity in Canada and because hydroelectric developments have long lead times, the impacts of the Enhanced Cooperation case are not large until the end of the projection period. Emissions are tabulated in Table A11-12 of the Appendix.

Emissions of CO_2, NO_X, SO_2 and CH_4 are all affected. Emission reductions, relative to the Current Tech case become evident as early as 1999 for SO_2 and drop by 3.9 percent relative to the Current Tech case by 2010. For CO_2 and NO_X, noticeable reductions occur after 2005. By 2010, CO_2 emissions drop by 2.4 percent and NO_X emissions by 1.6 percent. All these reductions are a result of the substitution of hydro for fossil fuel fired thermal generation. As well, fugitive release of CH_4 from coal mining is reduced 3.4 percent by 2010,

primarily a result of the reduced demand for eastern Canadian coal. By 2010, CH_4 releases from eastern mines are projected to be reduced by 33 percent relative to the Current Tech case. Reductions from western surface mines amount to only 1.3 percent.

11.7   SUMMARY AND CONCLUSIONS

The atmospheric emissions of CO_2, CH_4, SO_2, NO_X and VOCs arising from energy use are projected for the period 1993 to 2010. Amounts are calculated using published combustion emission factors and other techniques which were derived in consultation with Environment Canada and Natural Resources Canada. Projections are made for each of the Current Tech, the High Tech and Enhanced Cooperation cases.

The combustion of fuels in the transportation, residential, industrial and commercial sectors constitutes the predominant source of emissions of CO_2 and NO_X. Electric utility sector emissions dominate the SO_2 inventory. Emissions from the upstream oil and gas sector constitute a large portion of the total energy related emissions for many of the gases examined. Methane releases from coal mines and fugitive emissions of reservoir CO_2 constitute a relatively small proportion of the total energy related emissions of those gases.

Our analysis shows that energy-related emissions are closely tied to the overall level of economic activity. Emissions change with time in relation to a combination of growth factors and emission limits. The highest rate of growth in emissions is in the greenhouse gases – at present there are no emission standards or explicit limits for CO_2. For the acid forming gases, the effects of existing controls on SO_2 and NO_X are evident and emissions are projected to grow at relatively slow rates. For natural gas, although combustion emissions factors are relatively low, natural gas production and consumption are higher in the High Tech case than in the Current Tech case by the end of the study period. Thus total energy production and consumption and, therefore, total emissions are also higher.

When compared with projected emission levels published by NRCan[7], our projection of CO_2 emissions for 2010 are above their "reference scenario" but lower than their "higher economic growth scenario," reflecting our different assumptions about overall economic growth and energy intensity. Similarly, our projections of CH_4 emissions are higher than those of NRCan reflecting our assumptions regarding the growth of the natural gas sector, and more recent information on fugitive emissions from the upstream oil and gas sector.

Emissions in the transportation sector generally decrease with time as efficiency improvements are incorporated into vehicles. Similarly, controls on sulphur emissions in the utility industry serve to keep SO_2 emissions stable over time. When overall economic activity strengthens, transportation and utility sector emissions increase but at slower rates than in other sectors.

Fuel switching has both positive and negative impacts on emissions. In the High Tech case, where the demand for electric power is increasingly met through the use of natural gas rather than coal at the end of the projection period, CO_2 emissions decrease in the electric power sector in comparison with the Current Tech case. Furthermore when coal production is decreased, emissions of CH_4 from coal mines contribute a reduced proportion of the total emissions of that gas. However, SO_2, VOC and CH_4 emissions from the upstream oil and gas sector rise. In the Enhanced Cooperation case, when large scale hydroelectric projects are developed to serve regional loads, significant reductions occur in emissions of CO_2, SO_2 and NO_X.

Emissions could be further reduced through the introduction of measures to control emissions in several sectors. Moreover, as new production, storage and transportation facilities and as new handling procedures are developed for fossil fuels, fugitive emissions can be expected to decline. Reduction of combustion-based CO_2 emissions will pose a significant challenge as these respond primarily to changes in energy consumption and production. Efficiency enhancements in combustion technologies would be expected to reduce emissions of most pollutants.

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7   *Canada's Energy Outlook: 1990-2020 (Working Paper)*. Ottawa: Department of Natural Resources, September 1993.

Chapter 12

SOURCES AND USES OF ENERGY, SUMMARY AND CONCLUSIONS

In this chapter we first present a perspective on future trends in Canadian energy supply, demand and trade and then provide a summary of the main findings and conclusions of our analysis.

12.1 CANADIAN ENERGY SUPPLY, DEMAND AND TRADE[1]

Figure 12-1 shows energy flows in Canada and illustrates the relationship between the sources and uses of energy in 1991 and for the Current and High Tech cases in 2010.

In moving from primary sources of energy to end use demand, we first identify the sources of primary energy, consisting of domestic primary energy production and imports. Subtracting exports from these energy sources leaves domestic demand for primary energy.

To arrive at end use demand from primary energy, we subtract fuel use and losses incurred in producing, processing, transporting and distributing oil and gas, as well as conversion losses in electricity generation and fuel use and losses in electricity transmission and distribution.

Production

Production of primary energy is projected to increase by 3.2 percent per year from 1991 to 2000 in the Current Tech case and 2.9 percent per year in the High Tech case. These projections are similar to the growth of 2.8 percent per year during the 1980s, a period of strong export expansion (Figure 12-2).

During 2000-2010, total production declines in the Current Tech case, but increases by about one percent per year in the High Tech case.

The trends in the shares of production by fuel are mixed. The oil share declines after 2000, continuing the pattern established during the 1980s; the decline is less pronounced in the High Tech case where applications of new technologies tend to sustain oil production. The natural gas share continues to increase, although the rate of increase is more moderate in the near term in the High Tech case in which near-term exports remain close to recent levels. Coal's share declines in the High Tech case but increases during 2000-2010 in the Current Tech case as gas becomes more expensive.

On balance, hydro and nuclear maintain or marginally lose share, compared to 1991, in the Current

and High Tech cases. For nuclear generation, this is a reversal of the growth trend in the 1980s which reflected its increasing importance in Canadian energy production. We now assume that no new nuclear facilities will be built during the projection period.

Imports

With respect to trade in energy commodities, only oil and coal imports are large enough for there to be an appreciable difference between gross and net exports. In the Current Tech case oil imports rise from 1 535 petajoules in 1991 to 2 564 petajoules by 2010 (Table A12-1); the increase is somewhat less in the High Tech case due to higher domestic production. Coal imports increase to 745 petajoules by 2010 in the Current Tech case, about double the 1991 level; import requirements are lower in the High Tech case because gas is substituted for coal in electricity generation.

In 1991 Canada imported 21 petajoules of natural gas from the U.S. into Eastern Canada, equivalent to about one percent of Canadian primary demand. In the Current Tech and High Tech cases imports increase to about 400 petajoules by 2010, 13 percent and 9 percent of gas demand, respectively.

Canadian Primary Energy Demand

Primary energy demand is projected to grow steadily (Figure 12-3), averaging 1.7 percent per year during 1991-2010 in the Current Tech case. This is higher than the growth of the 1980s (0.9 percent per year), but substantially lower than the growth of the 1970s (3.9 percent per year). Projected growth is slightly higher in the High Tech case, averaging 1.9 percent per year.

The main changes in the fuel market shares result from our assumptions about end use gas prices. In the Current Tech case (relatively high gas prices), gas loses share to oil and coal over the study period. In the High Tech case gas gains share from oil, coal and hydro/nuclear. For the most part, the rank order of the fuel shares remains unchanged with oil and gas maintaining 55-60 percent of future demand compared to 58 percent in 1991. Overall, the change in shares is less dramatic than during the 1980s, which saw oil lose share to all other fuels.

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1   Canadian energy balances for the Current and High Tech cases are
    contained in Appendix Table A12-1.

FIGURE 12-1
Energy Flows[1]
(petajoules)

1991
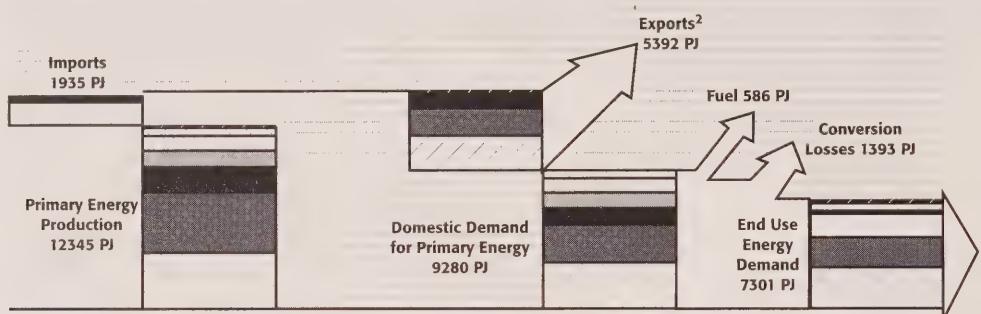
Current Tech – 2010
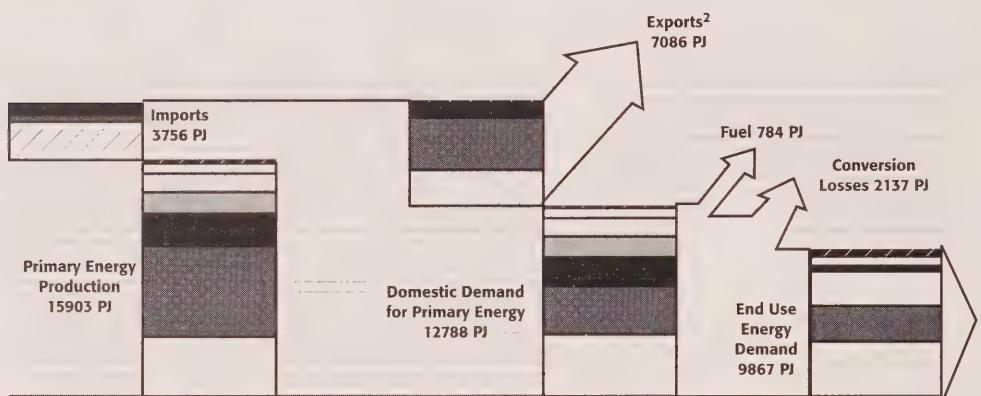
High Tech – 2010
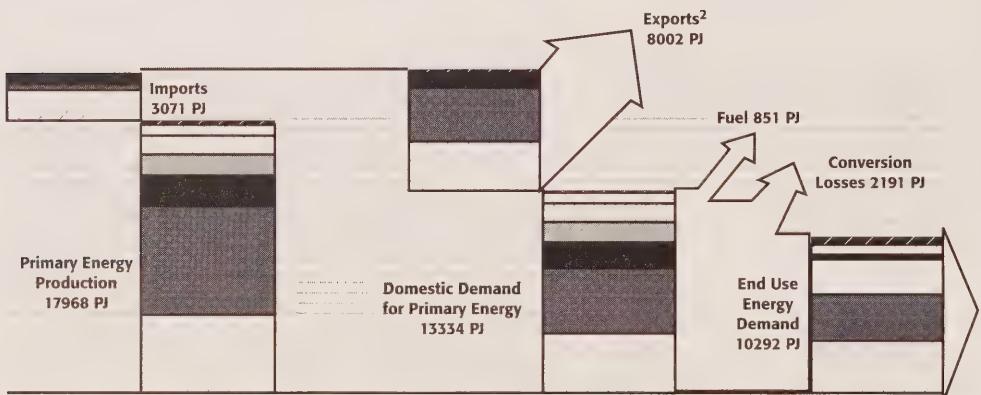
Legend:
- Other
- Nuclear
- Coal
- Natural Gas
- Renewables
- Hydro
- Electricity
- Oil

1991:
- Imports 1935 PJ
- Exports[2] 5392 PJ
- Fuel 586 PJ
- Conversion Losses 1393 PJ
- Primary Energy Production 12345 PJ
- Domestic Demand for Primary Energy 9280 PJ
- End Use Energy Demand 7301 PJ

Current Tech – 2010:
- Imports 3756 PJ
- Exports[2] 7086 PJ
- Fuel 784 PJ
- Conversion Losses 2137 PJ
- Primary Energy Production 15903 PJ
- Domestic Demand for Primary Energy 12788 PJ
- End Use Energy Demand 9867 PJ

High Tech – 2010:
- Imports 3071 PJ
- Exports[2] 8002 PJ
- Fuel 851 PJ
- Conversion Losses 2191 PJ
- Primary Energy Production 17968 PJ
- Domestic Demand for Primary Energy 13334 PJ
- End Use Energy Demand 10292 PJ

1   Source: Appendix Table A12-1. Supply and demand may not balance due to inventory changes, and differences between data sources in estimates of processing losses, pipeline fuel and energy conversion losses.
2   Exports include fuel and losses associated with electricity exports.

Exports

Energy exports are an important determinant of Canadian energy production. In 1991, 44 percent of primary energy production was exported; the share is projected to remain about the same by 2010 in the Current and High Tech cases. Oil exports accounted for 19 percent of primary energy production in 1991 and gas exports accounted for 15 percent. In 2010, the oil share is 15 percent in the Current Tech case and 18 percent in the High Tech case, with oil quality shifting more toward heavy crude; the gas shares are 22 and 20 percent respectively. The coal share declines from eight percent in 1991 to six percent in the both the Current and High Tech cases. NGLs remain at about one percent of exports.

Net Exports

Net energy exports (Table 12-1) increase in the range of four to five percent per year during 1991-2000 in the Current and High Tech cases. These trends suggest that energy trade will make a positive contribution to Canadian economic growth in this period. Net exports decline during 2000-2010; however, they still remain positive in total and compare favourably with recent levels.

Exports of natural gas clearly dominate. In the Current Tech case gas accounts for 94 percent of net exports by 2010, compared to 53 percent in 1991. The gas share drops to about 64 percent in the High Tech case reflecting higher oil production and, therefore, higher oil exports.

12.2   SUMMARY AND CONCLUSIONS

In this analysis of the prospects for Canadian energy supply and demand we have focused on the implications of:

- different natural gas supply conditions on demand and supply of all energy sources;

- evolving oil supply technologies and different oil prices for Canadian oil supply;

- a more energy-intensive economy for energy demand; and

- more interprovincial planning of electricity supply together with open access to transmission facilities for the pattern of electricity generation and trade.

Our analysis resulted in substantially different natural gas price profiles in the two gas supply cases analyzed; by 2010 Alberta fieldgate prices are projected to average about $4.00 and $2.25 in real terms in the Current and High Tech cases respectively, compared to the 1993 level of $1.58. We adopted a reference oil price projection which implies small increases in the prices of refined petroleum products and we assumed that electricity prices would remain constant in real terms. Thus, over our study period the only substantial change in relative energy prices at the burner tip is an increase in natural gas prices relative to the prices of electricity and petroleum products in the Current Tech case.

FIGURE 12-2

Primary Energy Production by Fuel – Canada

Growth in end use energy demand in all cases analyzed is higher than the rate of growth experienced in the 1980s for all major sectors. This is a result of a number of factors: projected increases in energy prices are moderate; in our view the adjustment of energy demand to the energy price increases of the late 1970s and early 1980s is largely complete; and, in our economic projections, growth in production is more concentrated in energy-intensive industries over our study period than it has been in the past 20 years.

Natural gas prices and the composition of economic growth have an important influence on end use energy demand. If relatively low gas prices are combined with an economic projection in which the output of energy-intensive industries grows relatively rapidly, end use demand is about one exajoule higher, or about ten percent, than if gas prices are higher and economic growth is less energy intensive. Moreover, natural gas demand increases much more rapidly in the High Tech case, in which gas prices increase relatively slowly, than in the Current Tech case.

The fuels used in electricity production and the geographical pattern of generating capacity are influenced substantially by the course of natural gas prices and the extent to which the provinces begin to jointly plan for electricity production and engage in more extensive, economically beneficial, interprovincial trade. In the Current and High Tech cases, which assume that planning continues to be done independently by provincial utilities, fossil fuel and hydro generation increase by similar amounts over the study period. In the case of fossil fuel generation the fuel selected

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FIGURE 12-3

Primary Energy Demand by Fuel – Canada
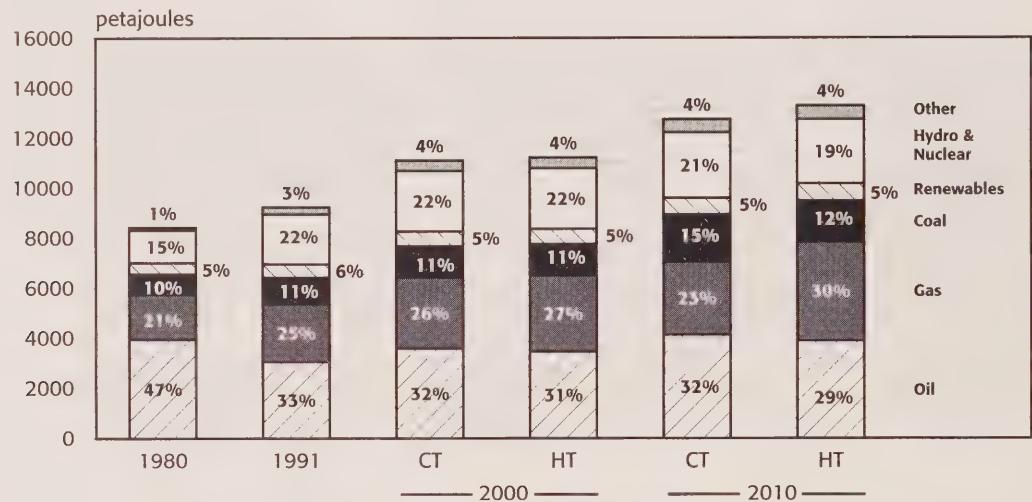
TABLE 12-1

Net Energy Exports[1]

(Petajoules)

	1980	1991	2000		2010	
			CT	HT	CT	HT
Coal	-26	584	440	437	204	317
Electricity	109	66	76	76	56	49
Natural Gas	863	1 788	3 073	2 290	3 074	3 137
NGL	222	181	302	164	108	160
Crude Oil & Products	-602	775	1 400	1 951	-157	1 228
Total	**566**	**3 394**	**5 291**	**4 918**	**3 285**	**4 891**

1 Negative values indicate net imports.

depends importantly on fuel prices. For example, in the High Tech case, in which natural gas prices are relatively low, the amount of natural gas-fired generation is double that of the Current Tech case.

In a setting in which electricity generating capacity is planned on an interprovincial basis and access to transmission is available, our analysis suggests that large hydro projects in Labrador and Manitoba, which are too large to be developed for intraprovincial use, would be developed to supply regional loads. Hydro production from Labrador would be transmitted through Québec to the Atlantic provinces, Ontario and possibly the U.S. Hydropower from Manitoba would be transmitted to Ontario and Saskatchewan. In this case we estimate that the Labrador and Manitoba hydro projects would displace all new fossil-fired generating capacity from Newfoundland to Saskatchewan in the second half of the next decade at a unit cost about 75 percent that of the fossil fuel alternatives. Consequently, total fossil-fuelled generation in this case is somewhat lower by the end of the study period than in the Current and High Tech cases.

The Board's analysis indicates that the WCSB natural gas potential resource is somewhat higher than the 1991 report due to a better understanding of the basin and advances in technology. Unconventional and frontier resources are unlikely to form a significant component of overall supply in the study period. Our estimate of U.S. resources, while higher than in 1991, is more conservative than most other estimates, mainly because of our approach to unconventional resources.

We analyzed the prospects for North American natural gas markets under a number of assumptions. The two principal cases examined alternative assumptions concerning the nature and costs of gas supply:

- the conventional resource continues to comprise the bulk of production and is increasingly expensive to exploit (the Current Tech case); and

- new advances in technology and geological knowledge prevent the costs of finding and developing new gas reserves from rising appreciably from current levels (the High Tech case).

We also analyzed the implications of a higher U.S. gas demand profile and of the impact on North American gas markets of the introduction of supply from an additional, low cost, non-Canadian source such as Mexico.

Canadian exports of natural gas are highest in a high price, high U.S. demand world and lowest in a low price world with abundant North American supply. In all but one case analyzed the projected exports from Canada are generally at or above levels recently experienced. Exports decline somewhat in the case which combines the High Tech view with the assumption of an additional low cost North American supply source.

The combination of expanding exports and domestic demand leads, under all cases studied, to rapidly rising production of Canadian gas over the next two decades. Exports are the most important influence. Our analysis suggests that Canadian production could reach the neighbourhood of seven exajoules per year towards the end of our study period compared to 4.7 exajoules in 1993.

The implications of rising gas production for exploration and development activity depend importantly on the assumptions made about the impact of technological change. In the Current Tech case modest improvements in known technology continue: in that case our projection implies that gas-directed exploratory drilling would increase rapidly from its 1993 level of two million metres to about five million metres per year near the end of the study period. In the High Tech case drilling and production technology are assumed to change in unspecified ways; therefore the projections emanating from this case are inherently uncertain.

The Export Impact Assessment suggests that the effects of assumed increases in gas exports on the key indicators (Canadian prices and availability of supplies) would not be very large, through the range of cases analyzed. In the Current Tech case Canadian production and hence exports can respond to higher demands until about 2005, when gas appears to be displaced by other fuels, due to its increasing price. In the High Tech case gas is able to supply all of the higher demand.

While there is uncertainty associated with the conclusions of a long term analysis of this nature the producing and consuming sectors appear to be able to accommodate the assumed level of exports. This analysis does not provide a specific understanding of adjustment difficulties, which are better addressed through a short-term analysis.

Canada's oil resource base is large and diverse, comprising conventional light and heavy oil in the WCSB, light oil in the frontier regions, and bitumen found in the oil sands in Alberta. Canadian oil supply has increased moderately in recent years as supply costs have declined due to industry rationalization and rapid technological progress. Among the new technologies, horizontal drilling has had a particularly strong impact on oil supply. We assessed the prospects for Canadian oil supply under two assumptions about the progress of technology: a

Current Tech assumption in which oil supply costs are related to technologies currently in use or which are close to becoming commercially viable, and a High Tech assumption which incorporates supply costs associated with technologies that are in the early stages of research. We also assessed the implications for oil supply of the upper and lower bounds of our sustainable range of oil prices (US$30 and US$15 per barrel, 1993 dollars).

Our analysis suggests that total Canadian crude oil production could increase over our study period so long as world oil prices are consistently above the mid-point of our sustainable range and/or technological progress further reduces supply costs. Any expansion in oil supply is likely to feature increases in heavy oil production, in bitumen production from the oil sands and light oil production from the frontiers. Light oil production from western Canada gradually declines over the study period. The state of resource depletion in the WCSB suggests that supply of western Canada conventional oil, particularly light crude oil, is unlikely to be sustained in the long run even under conditions of rapid technological progress. However, horizontal drilling and other new technologies may lead to a continued gradual increase in production in the near term and could delay the decline by several years.

The size and composition of the Canadian oil supply is very sensitive to oil prices between US$15 and US$26. In a world in which oil prices track at the bottom of the sustainable range, total Canadian crude oil supply declines quite rapidly as no new supply sources are economically viable. In contrast, all sources are viable above US$26. Canada remains a net exporter of crude oil when oil prices are sustained at or above the mid-range level. At lower prices Canadian production declines sufficiently rapidly that Canada becomes a net importer towards the end of the study period.

The NGL supply-demand balance is principally a function of natural gas production. Liquid yields are expected to decline modestly over the study period; however, overall production should increase, based on higher total gas production. Domestic demand for NGL is projected to increase, particularly ethane in the petrochemical sector and propane in the transportation and petrochemical sectors. The analysis indicates that there is a surplus of production over domestic demand for all NGL, implying that substantial volumes of these products will continue to be available for export.

Domestic coal demand is expected to show strong growth in the thermal power generation market, under the Current Tech assumptions, but growth is somewhat slower in the High Tech case. Canadian coal exports are uncertain. The analysis suggests that thermal coal exports could increase into an expanding world market, but increases would, to some extent, depend on the purchasers' desire to diversify their supply sources. Similarly, metallurgical coal exports could show some increases, but competing technologies such as PCI and EAF may limit this growth. Canadian producers need to remain price competitive in order to achieve export growth.

In general, alternate and renewable energy sources are higher cost than conventional sources. However, there are applications of renewable technologies, particularly the use of biomass, which account for significant portions of regional markets. While our projection does not feature a larger market share for alternate energy, total production does increase. Emerging technologies in this field may allow for a higher penetration into conventional markets should technological change result in substantially lower supply costs than we are currently projecting.

Our projections, like those in the Climate Change Report, imply that, absent the implementation of specific control measures, emissions of the greenhouse gases of carbon dioxide and methane will continue to rise with growing use of fossil fuels over our study period.

Of the other gaseous emissions, those of the nitrogen oxides rise moderately while energy-related emissions of volatile organic compounds and of sulphur dioxide decline over the study period. Emissions of carbon dioxide, nitrogen oxides and sulphur dioxide are lowest in the enhanced electricity trade case. In that case large amounts of fossil-fuelled electricity generation are displaced by hydro-electric generation.

There are wide ranges of possible and plausible outcomes for both energy demand and supply over the next two decades. Different outcomes result from variations in factors as diverse as economic activity, the pace of technological advance and, as in the case of electricity supply, the nature of trading and transmission arrangements. We do not present any one outcome as being more probable than another. Nor can it be said that, in general, any one outcome is more desirable than another.

The actual pattern of events will not be as smooth as suggested in our analysis. Markets will be required to adjust to changing circumstances and, as they do, fluctuations in volumes and prices can be expected to occur. We reiterate that our purpose has not been to engage in a detailed analysis or forecast of short-term developments; rather, it has been to shed some light on possible long-term trends.

GLOSSARY

Acid Rain

(Pluies acides) Rain water that is acidified by sulphuric, nitric, organic, or other acids.

Adjusted Productive Capacity (gas)

(Capacité de production rajustée [gaz naturel]) The estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production. (See also Productive Capacity).

Alkaline Flooding

(Injection alcaline) A chemical flooding process in which alkaline chemicals are injected into the reservoir to improve oil recovery.

American Petroleum Institute Scale

(Échelle de l'American Petroleum Institute) Measures the relative density of crude oil and oil products; the higher the number, the lower the relative density.

$$°API = \left(\frac{141.5}{\text{Specific gravity}} \right) - 131.5$$

AOSTRA Taciuk Process

(Procédé Taciuk de l'AOSTRA) A thermal process that employs a horizontal rotating vessel to separate organic material from sands or clays. The process is applicable to oilsands developments as it produces dry sand and a partially upgraded oil from bituminous oilsands. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Associated Gas

(Gaz associé) Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.

Avoided Cost

(Coût évité) The costs that would be incurred in the normal course of providing a service that are no longer incurred due to the implementation of an alternative process.

Backstop Cost (gas)

(Coût filet [gas naturel]) The lesser of: (i) the highest cost unit of gas likely to be produced at some future time, and (ii) the cost of the most easily substitutable fuel. The higher the estimated backstop cost, the higher the estimated user cost.

Base Load Capacity

(Capacité de production de la charge de base) Electricity generating equipment which operates to supply the load over most hours of the year.

Biochemical Conversion	*(Conversion biochimique)* Conversion of biomass to ethanol using chemical processes and organisms, including bacteria and fungi.
Biomass	*(Biomasse)* Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.
Bitumen	*(Bitume)* A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes, that has a viscosity greater than 10 000 millipascal-seconds (mPa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. Bitumen may contain sulphur and other non-hydrocarbon compounds and in its natural viscous state is typically not recoverable at a commercial rate through a well.
Blended Heavy Oil	*(Pétrole lourd mélangé)* Heavy crude oil to which light oil fractions have been added in order to reduce its viscosity to meet pipeline specifications.
Blowdown	*(Purge rapide)* The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Burner Tip Price (or Retail Price or Input Price)	*(Prix à la pointe [au bec] du brûleur [ou prix de détail ou prix d'alimentation])* The price of a fuel paid by the end user.
Butanes	*(Butanes)* In addition to its normal scientific meaning, a mixture mainly of butanes which ordinarily may contain some propane or pentanes plus.
Buy-Back Rates	*(Taux de rachat)* The price an electric utility pays for electricity produced by a non-utility generator.
Capacity (electricity)	*(Capacité [électricité])* The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.
Capacity Brokering	*(Courtage de la capacité)* The selling or renting by a shipper of its contracted pipeline capacity to others.
Capacity Factor	*(Facteur d'utilisation)* For any equipment, the ratio of the average production during a specified time period to the rated capacity (usually expressed as a percentage).

Carbonate

(Carbonate) A sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite).

Catalytic Conversion

(Conversion catalytique) A refinery process that utilizes catalysts in addition to pressure and heat to convert the heavier residual fuel oil to lighter products such as gasoline and diesel fuel.

Chemical Flooding

(Injection de produits chimiques) An improved recovery process in which water, with added chemicals, is injected into an oil reservoir to increase recovery.

Chemical Thermo-Mechanical Pulping

(Technique chimio-thermo-mécanique de la production de pâtes) Same as Thermo-Mechanical Pulping except that chemicals are added to the wood chips to further refine the pulp by removing the lignin.

Coalbed Methane Gas

(Méthane des gisements de charbon) The naturally occurring, dry, predominantly methane, gas produced during the transformation of organic material into coal. It is present as molecules adsorbed within the molecular structure of all coals, as gas in matrix porosity, as free gas in open fractures in coal, and as gas dissolved in ground water within the coal.

Coal Gasification

(Gazéification du charbon) The production of a synthetic natural gas from coal.

Co-generation

(Coproduction) A facility which produces steam heat as well as electricity, with a resultant overall improvement in energy conversion efficiency.

Coiled Tubing

(Tube d'intervention enroulé) A type of tubing which can be stored on a reel as a continuous string and uncoiled or coiled repeatedly as required. Coiled tubing has many applications in the petroleum industry, including drilling.

Coking Differential

(Différentiel de cokéfaction) This parameter compares the value of products obtained from light oil feedstock with the value of products obtained from heavy oil feedstock, both net of respective operating costs, based on yields from a typical coking unit. When the light/heavy oil price differential equals the coking differential, the profit margins to the refiner are the same for the two types of feedstock.

Coke Oven Gas

(Gaz de four à coke) A combustible gas that is the by-product of the production and combustion of coking coal and is used in the steel industry primarily for the heating of materials.

Combined Cycle Generation

(Production d'électricité mixte) The simultaneous production of electricity using both combustion turbine and steam turbine generating units. Electricity is first produced by one or more combustion turbine/generator sets fuelled usually by either natural gas or light fuel oil. The hot exhaust gases from this process are then used to generate steam which, in turn, drives a steam turbine/generator to produce electricity. A combined cycle block comprises one steam turbine as well as the combustion turbine(s) required to produce steam for that turbine.

Combined Drive Drainage

(Drainage combiné avec injection de vapeur) A process which combines horizontal producing wells with conventional steam drive using vertical wells for steam injection.

Conceptual Play

(Zone théorique) A play that does not yet have a discovery or reserves, but which geological analysis indicates may exist.

Continuous Sucker Rod

(Tige de pompage continue) A continuous rod that can be stored on a reel as a continuous string and serves as the connecting link between the surface pumping unit and the subsurface pump.

Condensate

(Condensat) A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a processing plant before the gas is processed in a plant.

Conventional Crude Oil

(Pétrole brut classique) Crude oil which at a particular point in time can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil. For the purpose of this report conventional crude oil is categorized as light or heavy crude oil, based mainly on the refining processes required to produce useful products. Our heavy crude oil category includes both heavy crudes and crudes which are classified by some others as medium.

Conventional Natural Gas

(Gaz naturel classique) Natural gas occurring in a normal porous and permeable reservoir rock which at a particular point in time can be technically and economically produced using normal production practices.

Conversion Capacity

(Capacité de conversion) The capacity of a refinery to increase its output of lighter products through the utilization of such processes as catalytic or thermal conversion.

Core Market (gas)

(Marché captif [gas naturel]) Generally that part of the gas market that does not possess fuel switching capability in the near-term; typically, residential, commercial and small industrial users.

Counter-Current Drum Separation (CCDS)

(Criblage à contre-courant [CCC]) A process which extracts bitumen from oilsands using a counter-current flow of water and bitumen in a drum separator. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Crude Oil and Equivalent Hydrocarbons

(Pétrole brut et hydrocarbures équivalents) Sometimes referred to as "Crude Oil and Equivalent". Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.

Cumulative Production

(Production cumulative) The total amount of hydrocarbons produced to a given date.

Cyclic Steam Stimulation

(Stimulation cyclique à vapeur) An improved recovery technique in which steam is injected into a reservoir through a well to reduce the viscosity of heavy crude oil. The well is then shut-in to allow the heat to dissipate and reduce the viscosity of the oil and the oil is subsequently produced using the same well through which the steam was injected.

Degree Day (or Heating Degree Day)

(Degré-jour [ou degré-jour de chauffage]) A (heating) degree day is a measure of the extent to which the average daily temperature is below 18°C. For example, if the average daily temperature were 16°C for a given location for a ten day period, the number of degree days recorded would be twenty. For days when the average temperature is warmer than 18°C, the degree days are recorded as zero. Degree days are used to indicate the amount of space heating required, other things being equal; for example, the higher the number of degree days, the colder the average recorded temperatures and the more space heating required.

Demand Side Management

(Gestion de la demande) Measures promoted by electric and natural gas utilities to favourably influence the amount and timing of customer energy demand.

Direct Reduced Iron

(Fer de réduction directe) A semi-metallic product that is produced by reducing iron-ore in its solid state to approximately 95 percent metallics, thus reducing the amount of carbon to be removed when the material is processed into steel.

Direct Rolling

(Laminage direct) A process by which steel billets or slabs go directly from a continuous casting machine to a rolling mill, thus eliminating the need to reheat the material after storage.

Direct Upgrading Technology (DUT)

(Technique de valorisation directe [TVD]) A technology designed to upgrade the emulsion produced by Sand Reduction Technology (SRT) to a low-quality synthetic crude oil. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Discovered Recoverable Resources

(Ressources découvertes et récupérables) Resources which are estimated at this time to be recoverable from known accumulations (i.e., accumulations which have been shown to exist by drilling, testing or production) using known technology. They include cumulative production, remaining reserves and "other discovered recoverable resources".

Down-Hole Motors

(Mouteur de fond) Cylindrical motors that are attached to the end of the drill string to rotate the drill bit, allowing drilling to proceed without rotating the entire drill string. These motors are widely used in the drilling of deviated and horizontal wells.

Efficiency of Fuel (or Burner Tip Efficiency)

(Rendement du combustible [ou rendement à la pointe du brûleur]) The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.

Electric Arc Technology

(Technique de l'arc électrique) Use of electrical arcs in a furnace to efficiently produce very high temperatures for applications such as metal melting and coating and industrial drying.

Electricity Production

(Production d'électricité) The amount of electric energy expressed in kilowatt hours or multiples of kilowatt hours produced in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load), the availability of fuels, the cost of fuels, stream flows and reservoir water levels, and environmental constraints.

Emission Factor

(Facteur d'émission) An estimate of the rate at which a substance is released to the atmosphere as a result of some activity (e.g., kilograms of sulphur dioxide emitted per tonne of coal burned).

End Use Demand for Energy (or Secondary Energy Demand) *(Demande d'énergie pour utilisation finale [ou demande d'énergie secondaire])* Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.

Energy Intensity *(Intensité énergétique)* In the industrial and commercial sectors and in transportation other than automobiles, energy intensity is defined as the amount of energy used per unit of production. In the residential sector it is energy use per household and for automobiles it is the average fuel economy of the car stock. A measure of the intensity with which energy is used in the economy as a whole is total end use energy per unit of real GDP.

Enhanced SAGD *(DGV amélioré)* A modified SAGD process which uses a pressure differential between adjacent well pairs to recover additional oil by steam drive. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Established Reserves (Oil and Gas) *(Réserves établies [pétrole et gaz naturel])* Those reserves recoverable under current technology and present and anticipated economic conditions, specifically those proved by drilling, testing or production ("proved reserves"), plus that judgement portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty ("probable reserves"). Established reserves are typically comprised of proved reserves plus one-half probable reserves.

Ethane *(Éthane)* In addition to its normal scientific moaning, a mixture mainly of ethane may contain some methane or propane.

Experimental Oil Project *(Projet expérimental sur le pétrole)* A pilot test to evaluate techniques for recovery of crude bitumen, crude oil, or condensate using methods that are considered untried and unproven in the particular situation.

Federal Energy Regulatory Commission The FERC is responsible for the regulation of all interstate trade in natural gas in the U.S. It regulates the tolls and tariffs of interstate oil and natural gas pipelines and approves the construction of new facilities. It also regulates the transmission and wholesale sale of electricity in interstate commerce, licenses non-federal hydroelectric projects, and oversees related environmental matters.

Feedstock *(Charge d'alimentation)* Raw material supplied to a refinery or petrochemical plant.

Fieldgate Price (gas)

(Prix après traitement [gaz naturel]) The price received by producers for natural gas delivered to a pipeline system (e.g., NOVA's pipeline system for Alberta).

Firm Power

(Puissance garantie) Electrical power intended to be available at specified times during the period of agreement for its sale.

Fluidized Bed Combustion

(Combustion sur lit fluidisé) A process in which combustion occurs in a bed of catalyst pellets maintained in a pseudo-fluid state by the passage of a gas through the pellets.

Fossil Fuels

(Combustibles fossiles) Hydrocarbon based fuel sources such as coal, natural gas and oil that are the by-product of the decay of ancient plants and animals whose remains are converted under great pressure in the Earth's crust over very long periods of time.

Frontier Areas

(Régions pionnières) Generally, the northern and offshore areas of Canada.

**Fuel Efficiency
(or Burner Tip Efficiency)**

(Rendement du combustible [ou rendement à la pointe du brûleur) See Efficiency of Fuel.

Fuel Switching Capability

(Capacité d'utilisation d'un combustible de remplacement) A customer's ability to use two or more fuels.

Fugitive Emission

(Émission fugitive) Any gaseous emission, other than from combustion (eg. escape of gases from valves, storage tanks, coal mines).

Gas Cycling

(Recyclage du gaz) The reinjection of part or all of the produced natural gas into the reservoir after removal of natural gas liquids.

Gas-in-place

(Gaz en place) see In Place Resources

Greenhouse Effect

(Effet de serre) A naturally occurring phenomenon in the earth's atmosphere in which incoming solar short-wave radiation passes relatively unimpeded, but long-wave radiation emitted from the warm surface of the earth is partially absorbed, adding net energy to the lower atmosphere and underlying surface, thereby increasing their temperature. The greenhouse effect is enhanced by the addition to the atmosphere of several trace gases. This phenomona is analogous to the way in which heat is trapped by the glass in a greenhouse.

Heavy Crude Oil

(Pétrole brut lourd) A term applied to crude oil having a high density; also a collective term used to refer to conventional heavy crude oil and bitumen. In this report, heavy crude oil supply and demand numbers include heavy crude oil as well as any light fractions added to reduce viscosity to facilitate pipeline transportation but exclude any conventional heavy crude oil or bitumen upgraded to light crude oil.

Heavy Ends

(Fractions lourdes) The heaviest in the range of products produced in the refining process. Normally such products are sold as heavy fuel oil or upgraded. Also referred to as the "bottom of the barrel".

Heavy Fuel Oil

(Mazout lourd) In this report, includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).

Hog Fuel

(Résidus de bois) Fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, saw mills and plywood mills

Horizontal Well

(Puits horizontal) A well which deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.

Huff-and-Puff

(Injection cyclique de vapeur) See Cyclic Steam Stimulation.

Hydraulic Fracturing (Fracing)

(Fracturation hydraulique) An operation in which special fluids are pumped down the well under pressure high enough to cause the formation to crack open to create passages for the reservoir fluids to more easily flow into the well bore.

Hydroelectric Generation

(Production hydro-électrique) Electricity produced by an electric generator driven by a hydraulic turbine.

Hydrotransport

(Hydrotransport) A process using water to transport oilsands through a pipeline. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Improved Oil Recovery (or Improved Recovery)

(Récupération assistée) See Recovery- Improved.

In Place Resources

(Ressources en place) The gross volume of crude oil, natural gas and related substances estimated at a particular point in time to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.

In Situ Recovery

(Récupération en place) The process of recovering crude bitumen from oil sands other than by surface mining.

Independent Power Producers

(Producteurs d'électricité indépendants) Electric power facilities built by private investors to serve load requirements of a utility or of an industry.

Initial Reserves

(Réserves initiales) Initial reserves is a term often used to refer to reserves prior to deduction of any production. Alternatively, initial reserves can be described as the sum of remaining reserves and cumulative production at the time of the estimate.

Initial Volume-In-Place

(Volume initial en place) See In Place Resources.

Input Price

(Prix d'alimentation) The actual purchase price of a fuel paid by the consumer (see also Burner-Tip Price).

Integrated Mining Plant

(Exploitation minière intégrée) A mining and upgrading operation where oil sand is mined from open pits and separated into sand and bitumen. The bitumen is then upgraded into synthetic light crude oil by a refining process.

Integrated Resource Planning

(Planification intégrée des ressources) A process used to identify the appropriate mix of all known resources that will minimize the cost and risk associated with providing energy services to society over the long run. Resources include traditional supply sources, as well as energy conservation and management of peak demand.

Kerogen

(Kérogène) A solid bituminous substance occurring in certain shales that decomposes to oil and natural gas when heated.

Light Crude Oil

(Pétrole brut léger) A term applied to crude oil having a low density; also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil, synthetic crude oil and pentanes plus. In this report, light crude oil supply and demand numbers exclude any light crude fractions added to heavy crude oil.

Light Fuel Oil

(Mazout léger) Furnace fuel oil (No. 2 fuel oil).

Load Factor

(Facteur de charge) The ratio of the average load during a designated period to the peak or maximum load during that same period (usually expressed as a percent).

Marginal Cost

(Coût marginal) The cost associated with producing one additional unit of output; also referred to as the incremental cost of production.

Marketable Natural Gas

(Gaz naturel commercialisable) Natural gas which meets specifications for end use, whether it occurs naturally or results from the processing of raw natural gas. It excludes field and plant fuel and losses, excepting those related to downstream reprocessing plants. The heating value of marketable natural gas may vary considerably, depending upon its composition.

Measurement While Drilling (MWD)

(Télémesure de fond) A technology enabling the transmission of information from downhole measuring devices to the surface while drilling is ongoing.

Methane

(Méthane) In addition to its normal scientific meaning, a mixture of methane which ordinarily may contain ethane, nitrogen, helium or carbon dioxide.

Methyl Tertiary Butyl Ether (MTBE)

(Éther butylique tertiaire de méthyle [EBTM]) A chemical additive derived from butane production that is used to enhance the oxygenate levels of motor gasoline.

Miscible Flooding

(Injection de fluides miscibles) An improved recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.

Multiple Leg Well

(Puits à branches multiples) A well in which several well bores extend from the initial hole drilled from the surface. Such extensions are frequently drilled from horizontal wells.

Natural Gas Liquids

(Liquides de gaz naturel) Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, pentanes plus and condensate and may include small quantities of non-hydrocarbons.

Nitrogen Oxides

(Oxydes d'azote) The primary nitrogen by-products of combustion are nitrogen oxide (NO) and nitric dioxide (NO_2) which are collectively known as nitrogen oxides (NO_X). Nitrogen oxides contribute to the formation of acid rain and are important in the production of ozone in the lower atmosphere.

Nitrous Oxide

(Oxyde nitreux) A chemically active trace gas which has a large number of natural sources and is a secondary product of combustion. Nitrous oxide is a strong greenhouse gas.

Nominal Energy Price

(Prix nominal de l'énergie) The price charged for an energy source in terms of money of the day.

Nominal Interest Rate

(Taux d'intérêt nominal) The rate of interest that prevails on any financial instrument and represents the rate of return on these instruments in terms of money of the day.

Nominal Personal Disposable Income

(Revenu personnel disponible nominal) The sum of the economy's sources of income such as labour income, interest income, rental income, subsidies and transfers, etc. less total direct income taxes, expressed in terms of the money of the day.

Non-Associated Gas

(Gaz non associé) Natural gas found in a reservoir in which no crude oil is present at original reservoir conditions.

Non-Utility Generation

(Production par une société autre qu'un service public) Electric power facilities built, owned and operated by specific industries or private investors to serve the industry's own electricity needs or to serve the electric utility load requirement.

Oil Price Sensitivities

(Sensibilités aux prix du pétrole) See Chapter 1, and Sections 2.1, 4.4, 6.12 and 7.10.

Oil Sands

(Sables pétrolifères ou sables bitumineux) Deposits of sand or sandstone, or other sedimentary rocks containing bitumen.

Oil Shale

(Schiste pétrolifère) A shale that contains kerogen, from which liquid hydrocarbons can be distilled

Oil-in-place

(Pétrole en place) See In Place Resources.

Open Access

(Libre-accès) The non-discriminatory access to pipelines or electricity transmission lines.

Orimulsion

(Orimulsion) A fuel that is comprised of heavy crude from the Orinoco region of Venezuela mixed with an emulsifying agent.

Other Discovered Recoverable Resources

(Autres ressources découvertes et récupérables) Those discovered resources that are estimated at this time to be recoverable using known technology but that have not yet been recognized as established reserves because of uncertain economic viability.

Output Price (end use)

(Prix d'utilisation finale) The implicit price of a fuel that results after adjusting the input price of the fuel for its fuel efficiency. For example, if fuels A and B have equal input prices but fuel A is twice as fuel efficient as fuel B then the output price of fuel B will be twice that of fuel A, since it will take twice as much of fuel B to yield the same amount of usable energy as fuel A (see also Efficiency of Fuel).

Overburden

(Morts-terrains) Rock and soil materials overlying mineable deposits such as coal seams.

Pay Zone

(Couche productrice) The interval of the stratigraphic section in an oil or gas reservoir that will yield oil or gas in economic quantities.

Peak Demand (electricity)

(Demande de pointe [électricité]) The maximum load consumed by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or, more usually, the average load over a designated short interval of time such as one hour (normally stated in kilowatts or megawatts).

Peak Demand (gas)

(Demande de pointe [gaz naturel]) The maximum amount of gas required by a customer or LDC over a short period of time (typically one day).

Peaking Capacity

(Capacité de pointe) Electricity generating equipment which is available to meet peak demand.

Pentanes Plus

(Pentanes plus) A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate or crude oil. For the purpose of this report pentanes plus includes condensate.

Permeability

(Perméabilité) A measure of the capacity of a reservoir rock to transmit a fluid (liquid or gas).

Petroleum

(Pétrole) A naturally occurring mixture of predominantly hydrocarbons in the gaseous, liquid or solid phase.

Petrophysics

(Pétrophysique) The study entailing the measurement of physical properties of rock formations.

Photovoltaics

(Dispositif photovoltaïque) Photovoltaic systems produce direct-current electric power from solar energy, using semiconductor materials.

Plug Load

(Charge des enfichables) The demand for electricity generated by appliances and machines that are typically "plugged in" to electrical wall sockets. For example, the growing use of electronic equipment, such as computers in offices, increases the plug load in office buildings.

Polymer-Assisted Waterflooding

(Injection de solution de polymères) A technique in which polymer is added to the injection water to improve oil recovery by reducing the tendency of water to flow through established channels and bypass unrecovered oil.

Potential Growth (Potential Economic Growth)

(Croissance économique potentielle) Represents the upper bound to economic growth for a given unemployment rate; however, growth could exceed potential for a period of time if there are underutilized resources (e.g., if the unemployment rate at the beginning of the period were higher than the given rate). Potential growth is approximately equal to the sum of labour force and productivity growth.

Primary Aluminum

(Aluminium primaire) Aluminum produced through the electrolytic process that turns alumina from bauxite ore into aluminum alloy of very high purity. This material is often injected into the smelting of secondary aluminum to enhance its purity level.

Primary Energy Demand

(Demande d'énergie primaire) Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g., coal to electricity), and energy used by suppliers in providing energy to the market (e.g., pipeline fuel).

Primary Recovery

(Récupération primaire) See Recovery – Primary.

Private Supply Cost

(Coût privé) See Supply Cost.

Productive Capacity

(Capacité de production) The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to plant turnarounds and operational problems. (See also Adjusted Productive Capacity).

Progressive Cavity Pump

(Pompes de cavité en progression) A cylindrical pump in which a helical rotor turns within a helical stator, creating cavities which spiral through the barrel of the pump.

Propane

(Propane) In addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane or butanes.

Pulping Liquor (also known as waste liquor or black liquor)

(Liqueur de pâte [aussi connue sous le nom de liqueur résiduaire ou de liqueur noire]) A substance primarily made up of lignin, other wood constituents, and chemicals which are by-products of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity, through thermal generation.

Rate of Take

(Taux d'extraction) The initial rate at which gas will be produced from an entity such as a well, pool, field or area. It is usually expressed as a ratio. For example, a rate of take of 1:7 300 means that 1 unit of production on a daily basis is obtained for each 7 300 units of reserves for the entity under consideration.

Raw Natural Gas

(Gaz naturel brut) Natural gas as it is produced from the reservoir prior to processing. It is gaseous at the conditions under which its volume is measured or estimated and it may include varying amounts of heavier hydrocarbons which liquefy at atmospheric conditions, and water vapour, and may also contain sulphur and other non-hydrocarbon compounds. Raw natural gas is generally not suitable for end use.

Real Energy Price

(Prix réel de l'énergie) The price of an energy source after adjusting for inflation in the general price level. In this report most real energy prices are expressed in 1993 constant dollars (Canadian or U.S.).

Real Interest Rate

(Taux d'intérêt réel) The rate of interest that prevails after adjusting the nominal interest rate for inflation in the general price level.

Real Personal Disposable Income

(Revenu disponible réel des particuliers) That level of income that results from the adjustment of nominal personal disposable income for the average annual rate of inflation in the general price level.

Recovery – Improved

(Récupération assistée) The extraction of additional crude oil, natural gas and related substances from reservoirs through a production process other than primary recovery. Improved recovery includes both secondary and tertiary recovery processes, such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding and the use of miscible and immiscible displacement fluids.

Recovery – Enhanced

(Récupération assistée) A term frequently used in Canada which is equivalent to improved recovery.

Recovery – Primary

(Récupération primaire) The extraction of crude oil, natural gas and related substances from reservoirs utilizing the natural energy available in the reservoirs and pumping techniques.

Recovery – Secondary

(Récupération secondaire) Secondary recovery is a term frequently used to describe the extraction of additional crude oil, natural gas and related substances from reservoirs through pressure maintenance schemes such as waterflooding or gas injection.

Recovery – Tertiary

(Récupération tertiaire) Tertiary recovery is a term frequently used to describe the extraction of additional crude oil, natural gas and related substances from reservoirs using recovery methods other than natural depletion or pressure maintenance. A tertiary process can be implemented without a preceding secondary recovery scheme.

Remaining Reserves

(Réserves restantes) Initial reserves less cumulative production at the time of the estimate.

Remote Sensing

(Télédétection) The collection of information about an object by recording devices not being in direct contact with that object. The term is commonly used to refer to the measurement of the earth's surface or near-surface physical properties via aircraft or satellite.

Reprocessing Plant

(Usine de retraitement) See Straddle Plant.

Reprocessing Shrinkage

(Pertes en cours de retraitement) That quantity of natural gas removed from main gas transmission systems at straddle plants and converted to NGL, expressed in either volume or energy units.

Reserves Additions

(Additions aux réserves) Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserve estimates for established pools.

Reserves Appreciation

(Valorisation des réserves) Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.

Reserves Life Index or Reserves to Production Ratio

(Indice de durée des réserves ou Ratio réserves/production) Remaining reserves divided by annual production.

Reservoir

(Gisement) A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil, natural gas and related substances that is confined by impermeable rock or water barriers, and is individual and separate from other reservoirs.

R-2000 Homes

(Maison R-2000) A designation, established in 1980 by Energy Mines and Resources Canada (now Natural Resources Canada), for homes characterized by high levels of insulation, control of air leakage by means of improved air barrier sealing techniques, mechanical ventilation systems (often coupled with heat recovery), improved heating systems, and utilization of passive solar energy.

Sand Reduction Technology (SRT)

(Technique de réduction du sable) Technology designed to remove 90 percent of solids at the mine site using a low-temperature separation process and partly emulsifying bitumen for transport. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Sandstone

(Grès) A sedimentary rock consisting of compacted sand sized quartz grains, sometimes bound together by a cementing material. Several varieties of sandstone are recognized, based on their mineralogy and the nature of the binding material.

Scrubber

(Laveur) A device for the removal, or washing out, of entrained liquid droplets or dust, or for the removal of an undesired gas component from process gas streams. The purpose is to reduce the quantity of contaminants emitted into the air from the stack of a thermal generating station.

Secondary Aluminum

(Aluminium de deuxième fusion) Secondary aluminum consists largely of recycled (or scrap) aluminum products and, with further processing to enhance its purity level, yields various types of aluminum alloys for specific purposes.

Shale Gas

(Gaz de schiste) The dry, predominantly methane, gas produced from the fractures, micropores and bedding planes of shales. In order to produce gas these shale reservoirs must be stimulated by acidifying, fracturing or use of explosives.

Shrinkage

(Pertes en cours de traitement) That quantity of natural gas removed at field processing plants for recovery of liquids and by-products, removal of impurities, or used as fuel.

Slim Hole Drilling

(Forage à petit diamètre) Drilling of small-diameter holes (typically 4 inches or less compared to 8.5 inches or more for typical conventional wells) with the aim of reducing costs.

Solar Energy – Active System

(Énergie solaire – système actif) Solar energy collection system which transfers heat captured from solar radiation through mechanical devices.

Solar Energy – Passive System

(Énergie solaire – système passif) Solar energy collection system which captures solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.

Solution Gas

(Gaz en solution) Natural gas dissolved in crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.

Solvent Flooding

(Injection de fluides miscibles) See Miscible Flooding.

Sour Gas

(Gaz acide) Natural gas containing hydrogen sulphide or carbon dioxide.

Spot Price (Gas)

(Prix sur le marché du disponible) Generally, the price applicable to a sale of gas under a 30-day contract or less.

Stand Alone Upgrader

(Usine de valorisation indépendante) An upgrading facility that is not associated with a mining plant or a refinery.

Steam-Assisted Gravity Drainage (SAGD)

(Drainage par gravité au moyen de la vapeur [DGV]) A recovery scheme that allows extraction of heavy oil or bitumen by steam injection and gravity drainage. The technique entails drilling pairs of horizontal wells, one above the other, from underground tunnels or from the surface. Also, see "Bitumen Recovery Technologies" inset in section 7.5.1.

Steam Flooding

(Injection de la vapeur) An improved recovery technique in which steam is injected into a reservoir to reduce the viscosity of the crude oil. The injected steam, which condenses in the reservoir, also provides the energy to drive the crude oil to the producing wells.

Straddle Plant

(Usine de chevauchement) A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.

Straight Fixed-Variable Tolling (SFV)

(Établissement de droits selon la formule fixe-variable) Fixed and variable pipeline charges for firm transportation. All fixed costs, including: depreciation, return on equity and related charges, are recovered by the pipeline in its charge for capacity, regardless of volumes transported. All variable costs are applied based on the actual volumes transported.

Stratosphere

(Stratosphère) A layer in the upper atmosphere between about 10 and 50 kilometres characterized by cold temperature and low turbulence. Most of the ozone which absorbs ultra violet radiation is contained in this layer.

Sulphur

(Soufre) Sulphur, as used in the petroleum industry, is the elemental sulphur recovered by conversion of the hydrogen sulphide extracted from crude oil, natural gas or crude bitumen.

Sulphur Dioxide

(Dioxyde de soufre) Refers to gaseous sulphur dioxide (SO_2). In some cases, emissions may contain small amounts of sulphur trioxide (SO_3) and sulphurous and sulphuric acid vapour. Excludes particulate or aerosol sulphate.

Supply Cost

(Coût des approvisionnements ou coût de l'offre) Gas or oil supply costs express some or all costs associated with resource exploitation as an average cost per unit of production over the project life. The main cost components are: capital costs associated with exploration (geological and geophysical surveys and exploration drilling), development (development drilling and surface facilities), production operating costs, federal and provincial taxes, resource royalties and the threshold rate of return.

Surfactant Flooding

(Injection d'un agent tensioactif) A technique in which a soap-like chemical is injected along with other chemicals into the reservoir to reduce the oil/water interfacial tension and, ultimately, to increase oil recovery.

Synthetic Crude Oil

(Pétrole brut synthétique) A mixture of hydrocarbons similar to crude oil derived by upgrading crude bitumen from oil sands, kerogen from oil shales, or other substances such as coal. It may contain sulphur or other non-hydrocarbon compounds.

Synthetic Natural Gas

(Gaz naturel synthétique) Natural gas produced from petroleum liquids, coal or wood.

Thermal Conversion

(Conversion thermique) A refinery process that uses heat to convert the heavier residual oil to lighter products.

Thermal Generation

(Production thermique) Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity. Normally, the fuel may be coal, gas, fuel oils, biomass or uranium (nuclear).

Thermochemical Conversion

(Conversion thermochimique) Conversion of biomass to gaseous or liquid fuels such as methanol, using heat and chemical processes.

Thermo-Mechanical Pulping

(Production thermomécanique de pâtes) A process used in the pulp and paper industry in which electrically produced mechanical energy is used to steam and refine wood chips into pulp. The steaming process softens the wood chips with the result that the pulp produced is of a higher quality than that obtained from other processes. Recovered steam may be used for space heating or for drying fibres.

Three-Dimensional Seismic Survey (3-D Seismic)

(Étude sismique tridimensionnelle) The gathering of seismic data in a closely spaced grid, from a prospective hydrocarbon area, using artificially created sound waves. This data is then enhanced through computer processing to display the spatial relationships of the geological formations in three dimensions, in contrast to the conventional display in two-dimensional cross-sections along the line of survey.

Tight Gas

(Gaz d'une formation imperméable) Natural gas contained in low permeability reservoirs.

Total Factor Productivity

(Facteur de productivité totale) That portion of output that cannot be directly attributable to inputs such as labour and capital but represents output gains that result from efficiency improvements in the interaction of labour and capital.

Transfer Capability

(Capacité de transfert) The overall capacity of the interprovincial or international power lines, together with the associated electrical system facilities, to transfer capacity and energy from one electrical system to another.

Ultimate Recoverable Resource Potential

(Potentiel ultime de ressources récupérables) An estimate, at a given point in time, of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, other discovered resources and undiscovered recoverable resources.

Unbundled Rate

(Taux séparé) A rate for an individual, separate service offered by a pipeline or distributor.

Unconventional Crude Oil

(Pétrole brut non classique) Crude oil which is not classified as conventional crude oil. An example of unconventional crude oil would be bitumen.

Unconventional Natural Gas

(Gaz naturel non classique) Natural gas which is not classified as conventional natural gas. An example of unconventional natural gas would be coalbed methane.

Under-Balanced Drilling

(Forage sous-équilibré) A method of drilling in which the hydrostatic pressure exerted by the column of drilling fluid in the wellbore is kept below reservoir pressure through the injection of gas, commonly nitrogen, into the drilling mud. The method is used to minimize damage to the formation, thereby optimizing production.

Undiscovered Recoverable Resources

(Ressources récupérables pas encore découvertes) Resources that are estimated at a point in time to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence, but which have not yet been shown to exist by drilling, testing or production.

Upgrading

(Valorisation) The processing of bitumen or heavy crude oil into a synthetic crude oil.

User Costs	*(Coûts d'utilisation)* See Appendix A6.1.
Vaporized Extraction	*(Extraction vaporisé)* A process similar to SAGD but using a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
Viscosity	*(Viscosité)* The measure of the resistance of a fluid to flow.
Volatile Organic Compounds	*(Composés organiques volatils)* Includes only photo-chemically reactive hydrocarbons. Excludes methane, ethane and chlorinated organics.
Waste Fuels	*(Combustible résiduaire)* Fuel consisting of paints and coatings, surplus oils and greases, solvents and old tires that can be burned in high temperature ovens such as those used in the cement industry.
Water Coning	*(Formation d'un cône d'eau)* The cone-shaped encroachment of water around the wellbore in an oil or gas zone underlain by bottom water. The height of the cone depends on the rates of production.
Waterflooding	*(Injection d'eau)* An improved recovery process in which water is injected into a reservoir to increase recovery.
Wellhead	*(Tête du puits)* Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.
Wellhead Price (gas)	*(Prix à la tête du puits [gaz naturel])* The price received for gas by producers, net of any gathering or processing costs.
Wheeling Electricity	*(Électricité en transit)* The transmission of power belonging to one utility through the circuits of another utility for the delivery either to a third party or back to the originating system.
Wood Waste	*(Résidus de bois)* Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills (see also Hog Fuel).
Wood Wastes	*(Déchets de bois)* Refers to wood waste and pulping liquor.

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